Safe

Reliable

Responsive

Commercial

Focused

Annual Report

hydro One

105-03448/

Who we are

Hydro One Inc. is the largest electricity delivery company in Ontario and one of the largest in North America. Founded on nearly a century of operational excellence and expertise, Hydro One began operation in 1999, after legislation restructured Ontario Hydro's delivery and generation functions, dividing them into separate companies.

Our business is made up of three businesses — transmission, distribution and telecom. Transmission and distribution operations, representing 99% of our business, are regulated by the Ontario Energy Board.

Hydro One Networks Inc.

Hydro One Networks, our largest subsidiary, is involved in the planning, construction, operation, and maintenance of our transmission and distribution network.

Our transmission system carries electricity from generating stations to local distribution companies and large industrial customers through our high-voltage network of transformer stations, transmission towers and wires.

We own 97% of transmission in Ontario with almost 30,000 kilometres of high-voltage transmission lines. We also own and operate 26 interconnections with neighbouring provinces and states, which allow electricity to flow into and out of Ontario.

Our distribution system delivers electricity at lower voltages to homes, farms and businesses through our network of hydro poles and power lines. Our network is the largest in the province, with almost 123,000 kilometres of wires serving 1.2 million customers, mostly in rural areas.

Hydro One Brampton Inc.

is our subsidiary which distributes electricity to one of the fastest growing urban centres in Ontario.

Hydro One Remote Communities Inc.

operates and maintains the generation and distribution assets used to supply electricity to 19 remote communities across northern Ontario that are not connected to the province's electricity grid.

Hydro One Telecom Inc.

is involved in marketing our excess fibre-optic capacity. Our telecom business is about 1% of our total assets.

Accomplishments in 2002

- Strong financial performance: $344 million in net income and maintenance of earnings coverage ratio in line with historical results
- Met or performed better than our health and safety and environmental targets
- Established customer advisory board to identify customer issues and enable us to take action to improve customer satisfaction
- Eliminated a layer of management at the executive level to streamline decision-making and enhance productivity
- Upgraded and maintained the electricity network through $546 million in capital expenditures, helping to ensure the long-term integrity of the system
- Exited or sold non-core functions to ensure a clear focus on core business of electricity delivery

Key Strengths

- One of the largest electricity delivery companies in North America
- Expertise in electricity delivery in both low-density and urban environments
- Industry-recognized for expertise in development and implementation of safe work practices
- Track record of stable, predictable earnings
- Successful innovator of new tools and work practices now used throughout industry
- Highly skilled, experienced work force
- Experienced, commercially focused management team

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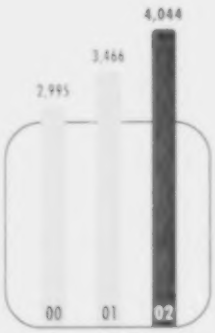
Consolidated Financial Highlights

Year ended December 31 (Canadian dollars in millions)	2002	2001	$ Change	% Change
Revenues	4,044	3,466	578	17
Purchased power	1,871	1,267	604	48
Operating costs	1,243	1,208	35	3
Net income	344	374	(30)	(8)
Operating cash flow	691	726	(35)	(5)

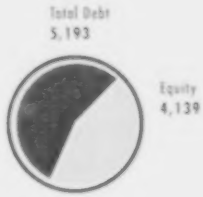
Statistics

Transmission – units transmitted *(TWh)*	153.2	146.9	6.3	4
Distribution – units distributed *(TWh)*	27.1	21.3	5.8	27



Revenue
Year ended December 31
(Cdn $ millions)

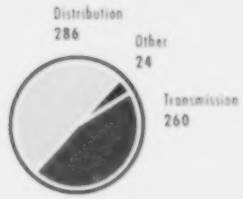
Net Income
Year ended December 31
(Cdn $ millions)



2002 Capital Structure
December 31
(Cdn $ millions)

EBITDA
Year ended December 31
(Cdn $ millions)

Earnings Coverage Ratio
Year ended December 31



2002 Capital Expenditures
Year ended December 31
(Cdn $ millions)

Message to Stakeholders

Our accomplishments over the past year have transformed us into a more flexible company. We've gained a fresh momentum and a renewed sense of purpose.

Renewing our focus on core operations

As the largest transmission and distribution company in Ontario, Hydro One has the responsibility to deliver power in a safe and reliable manner. As a provincially owned utility, we also have the responsibility to provide a return on investment to our shareholder by employing sound commercial practices. We are pleased to report that we fulfilled both of these responsibilities in 2002.

The summer of 2002 was one of the warmest in recorded history, leading to unprecedented demand for power. The professionalism and skill of our staff, and our robust transmission network enabled us to pass the test of peak demand time and time again over a hot and stormy summer. And in spite of challenging conditions, our employees worked safely, surpassing our 2001 safety record.

Hydro One also demonstrated sound financial performance. We earned net income of $344 million, and we paid $192 million in dividends to our shareholder. At the same time, we maintained our earnings coverage ratio at more than 2.3 times, in line with historical performance. Through ongoing improvements to our operations, we are well-positioned to continue to meet these important goals in the future.

Focus on the core

Our mandate is clear, and we have streamlined our operations to focus on our core strength — delivering electricity to our customers in Ontario. We continued to refine our management practices to ensure we make cost-effective decisions that respond to the needs of our customers. We also made significant progress toward ensuring that each of our lines of business is able to achieve acceptable cost-efficiencies and competitive advantage.

We have eliminated an entire layer of management at the senior level, and we have merged our two largest subsidiaries, further streamlining the operation of our asset management model. The result is a more efficient decision-making process and reduced bureaucracy.

We've reduced costs where possible and prudent, created forums for ongoing customer communication, made changes to tools, processes and systems to help our employees work more productively, and made responsible investments in our transmission and distribution systems. The steps we've taken to restructure our organization, and streamline our management to ensure a tighter focus on day-to-day operations, will enable us to deliver further efficiencies going forward.

A strong financial picture

Hydro One has enjoyed considerable financial success over the past year, and has continued to earn a positive response from the investment community. We have demonstrated an ability to respond favourably to financial challenges and we are well-positioned to maintain this consistent financial performance.

This year's results reflect our ability to earn a stable rate of return while providing our customers with lower distribution rates and incurring higher than normal network maintenance costs as a result of severe storms. The Ontario government announced on November 11, 2002 that it had capped transmission and distribution rates until at least 2006. The rate cap, coupled with system investment requirements, underscore the need for us to continue to manage our costs aggressively.

While the imperative to manage fiscal pressure is clear, any actions must be undertaken prudently and must not compromise the safety of our employees or our customers in any way. Our accomplishments in 2002 have demonstrated our commitment to those principles.

Performing safely under pressure

The challenges faced by our front line crews in restoring and maintaining the electricity systems, especially in a year of abnormally high storm activity, highlights the dangers that are an inherent part of our work. That's why our employees make sure that safety comes first in every decision they make — a commitment that is enshrined in our new employee health and safety policy.

That emphasis on safety extends to the communities we serve. We've invested significant resources in our continuing public safety programs, which are designed to create awareness of the risks of electricity and encourage prevention of injuries.

Improving customer service

Regular communication with our customers is an essential part of our business. When we discovered that some of our customers weren't satisfied with the level of service they were being provided, we invited a representative group of them to participate in a customer advisory board. This new forum will help us better understand our customers' needs, consult with them on proposed policy or service changes, and identify opportunities to improve.

Employees are our strength

Our success in 2002 is due in large part to the efforts of our employees. Our employees understand that they are providing a critical service to the residents and businesses of Ontario and they embrace the responsibility this brings with it.

This year, front line staff continued to develop and introduce new tools and work practices that will help employees work more efficiently, more effectively and with a higher level of personal and public safety. We take great pride that others in the electricity industry are adopting some of these innovations for their own use. Our trades-related training for power line maintainer apprentices is just one example of how we are setting the industry standard.

We're also very proud of the spirit of generosity among our employees who contribute their time and money to worthy causes. This year, Hydro One employees and pensioners raised an impressive $640,000 to benefit more than 800 charities across Ontario.

This year was an extraordinary one in many ways, and we thank our employees for rising to the occasion and performing their jobs under challenging circumstances. The professionalism and dedication of the Hydro One team in 2002 has helped us to achieve our financial and operating targets, and to ensure that we are well-positioned to fulfill our current responsibilities — and meet future challenges.

Glen Wright
Chair

Tom Parkinson
President and
Chief Executive Officer

Left to Right »

Glen Wright
Chair

Tom Parkinson
President and
Chief Executive Officer

Hydro One delivered in 2002

We are the people, the wires and the towers that deliver electricity safely and reliably to the residents and businesses of Ontario.

John MacDonald and Rudy Korec, Lines

Wood pole replacement in Allanburg

To fulfill our responsibilities to our customers, our shareholder, the Government of Ontario, and debt holders, we concentrated our efforts in 2002 on achieving superior operational performance in our transmission and distribution systems. We maintained this focus during a time of significant change in the industry, and without compromising our strong commitment to public and workplace safety.

In 2002, we focused on five key activities that will position us to be the best wires company in the business and deliver value to our shareholder:

- Streamlining our operations
- Investing in our assets
- Enhancing customer service
- Improving our productivity
- Connecting with our communities

Our success in focusing on these activities continues to enhance the financial strength of the company.

Streamlining our operations

To ensure that we can continue to deliver power safely and reliably to our customers, we must ensure that we are operating at optimal efficiency and generating sufficient capital to invest in and maintain our assets.

That has meant streamlining our operations in 2002 to concentrate on delivering excellent service to our customers through a stronger and more robust transmission and distribution system.

In 2000, Hydro One implemented the Asset Management Model to take advantage of synergies available from the joint operation of our transmission and distribution businesses. Previously, our transmission and distribution systems were operated as separate businesses with their own infrastructure, despite being subject to the same regulator, and facing similar operating issues with respect to terrain and service requirements.

Under the new model, a single group manages investments and service provision for both businesses. The model separates decision from execution, or asset management from service provision, given that the two functions require very different skill sets, competencies and focus. We are now able to manage and implement our maintenance programs more effectively, resulting in a more even distribution of workload and expenditures throughout the year.

In 2002, we further refined the asset management model by combining the asset managers and service providers within the same subsidiary. In doing so, we have eliminated the bureaucracy associated with formal contracts and now employ a more streamlined, work-order management process.

We recognized the need to streamline our decision-making process and eliminate bureaucracy to be responsive to new and evolving requirements. We eliminated a layer of management at the executive level, resulting in a smaller, more flexible management team able to react quickly and decisively to changing conditions.

We also announced the reduction of 140 employees, primarily from the head office management and management support areas. Our head office team is now much leaner and better positioned to support our core business operations.

Focusing on our core business

This year, we recognized that to continue to excel in our core business, we needed to concentrate our expertise and energy. We made the decision to exit businesses or functions where we lacked sufficient scale or competitiveness to maximize shareholder value, or where the risks were inconsistent with the risk profile of the company.

We signed an agreement with Inergi LP, which now provides a range of our back office functions, including information technology, customer service support, procurement and certain accounting functions and pay operations. This agreement, which went into effect March 1, 2002, will allow us to provide the same high-quality service to our customers while reducing our costs over the next 10 years.

We also exited the retail market for selling electricity and natural gas contracts and water heater rental agreements by selling Ontario Hydro Energy Inc. to Union Energy Inc. on April 30, 2002. Divesting this asset also allowed us to eliminate our exposure to fluctuating commodity prices, improving the overall risk profile of the company.

Investing in our assets

In 2002, Hydro One continued its ongoing maintenance and construction programs that help to ensure the long-term integrity of the transmission and distribution systems. These investments totaled $546 million this year, and covered a broad range of projects.

We performed maintenance at more than 250 transformer stations and 1,000 distribution stations from Ottawa to Windsor to Kenora. Some 3,200 circuit breakers, 2,500 transformers, and 1,100 switches were upgraded or serviced. More than 120,000 distribution wood poles were tested, and we replaced 5,000 that were identified as having reached the end of their life span.

Hydro One invested $38 million to expand and upgrade the capacity of the distribution system in 140 projects across the province. These ranged from new power lines in Essex County to installing new equipment to increase voltage capacity in the Walkerton area.

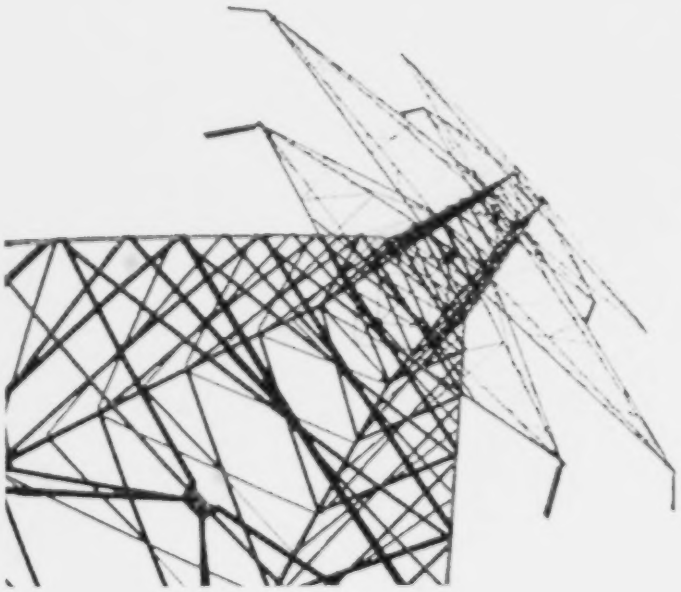
We also completed a $13-million rebuild of a transmission circuit in the Sudbury-Nipissing area. Originally constructed in 1937, this key section of line is 40 kilometers long and supplies power to a local foundry, three northern communities, is connected to local generation, and serves as a corridor that allows us to supply power to other parts of northern Ontario.

Improving customer satisfaction

This year, our customer satisfaction surveys revealed that we were not meeting the expectations of some of our customer groups. To help identify existing issues, and to ensure ongoing communication and feedback, we created a customer advisory board. The group is comprised of a cross-section of customers including end-users, transmission and distribution – connected industrial corporations, local distribution companies, and associations representing different customer segments.

The group began meeting in late 2002, and the initial sessions provided some valuable insight. We have begun to implement some of the board's suggestions and have received positive feedback from our customers. This approach will help us ensure that we receive customer input on an ongoing basis to enable us to address challenges. We will also have a forum to discuss proposed policy or procedure changes, and capitalize on opportunities in the initial planning stages.

Our mass market customers gave us high marks for our customer education efforts around the changes to their bill format and other industry changes. Our customer satisfaction surveys indicated that our customers felt well-informed about the changes in the industry, and we received fewer calls to our customer communications centre than we had anticipated.



Scheduled feather (transmission tower arms) replacement in Mississauga

Creating additional value by leveraging our fibre-optic network

Leveraging our core competencies

Hydro One has always received industry recognition for technical expertise in our core business. Combined with our success in becoming more cost-efficient, that reputation has won us recent contracts with external customers. This year, for example, we won a $19 million contract to design and build two transformer stations for Hamilton Hydro, to be completed by the summer of 2003.

Our success in this competitive bidding process is a clear demonstration of our ability to work with our customers to deliver a product that meets their needs at a competitive price. The unique design of the stations was developed in response to specific customer needs, sending a message to other potential customers that we are capable of developing innovative, flexible solutions.

Through our subsidiary Hydro One Brampton, we continued to gain valuable urban network skills, including expertise working with residential developers and high-density underground distribution systems.

For example, construction of a $14-million state-of-the-art transformer station in Brampton was completed this year, which services the load demands of one of the most rapidly growing population bases in the province. Because it is located in a residential area, the station was designed and constructed to harmonize with its surroundings. The unique project specifications required most of the equipment to be housed inside, which in turn required us to use the latest in switching technology and transformer construction.

Our Hydro One Telecom business is an example of how we're leveraging our existing assets to create additional value for Hydro One. We own one of the largest fibre optic networks in the province, which we use to monitor our transmission network. Hydro One Telecom markets our excess fibre optic capacity to telecommunications companies and other major users like hospitals, municipalities and large corporations.

Hydro One Telecom, working with Enersource Telecom, signed an agreement with Dufferin-Peel Catholic District School Board and Peel District School Board to establish a multi-million dollar fibre optics infrastructure. The introduction of this high-speed network gives the school boards the capacity to provide their students and faculty with greater access to advanced curriculum, research, and professional development resources in a cost-effective manner.

Hydro One Networks employee Keith McDonell with wife Sara Farrell and daughters Julia and Sophie

Doing what we do better: improving productivity

In order to ensure the continuing reliability of the service we provide to our customers, while maintaining rates at their current levels, we continued to reduce costs and improve productivity in our operations through process reengineering and innovation.

A safer workplace

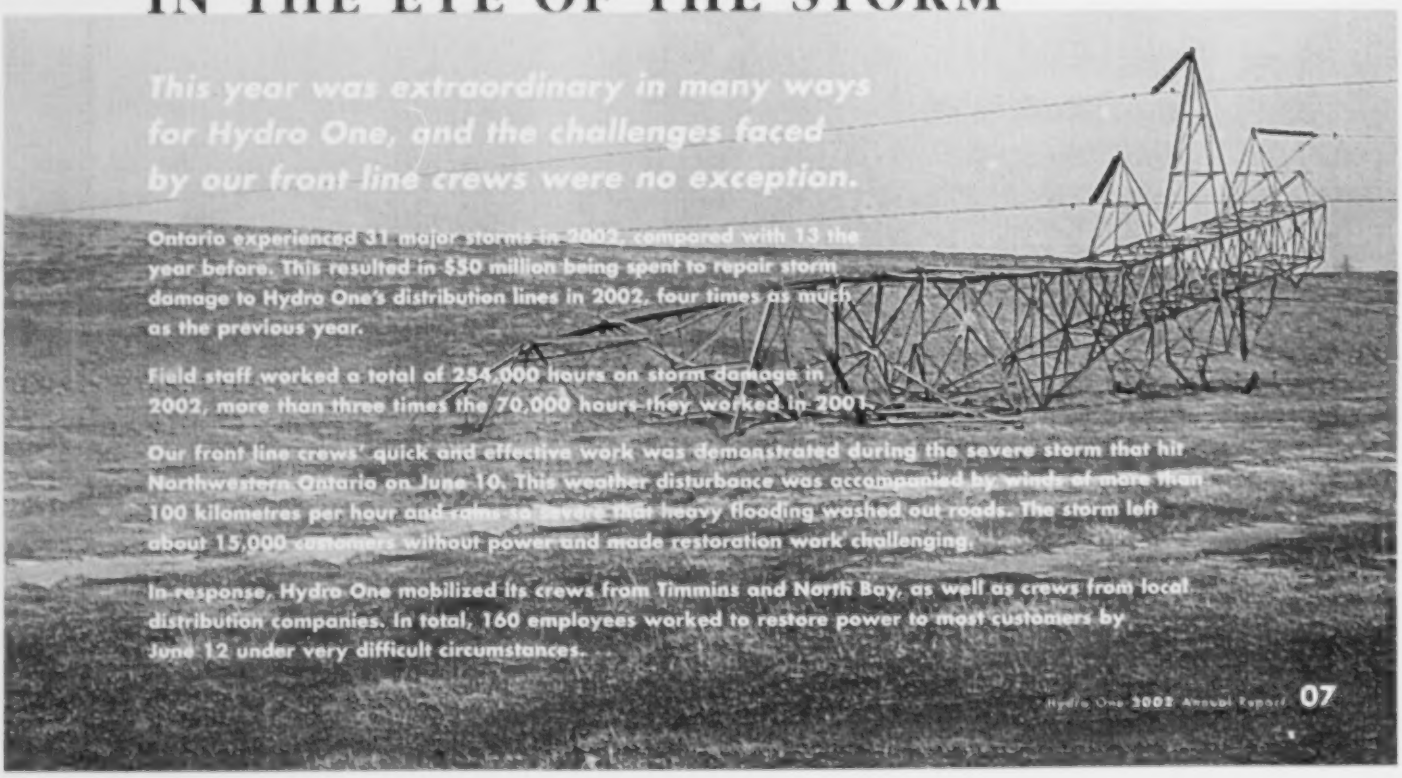
As an employer in an industry that has significant inherent dangers, employee and public safety is of paramount importance to the way we do business. Although we performed better than our 2002 targets, efforts are continuing, especially in the area of prevention, in order to achieve an injury-free workplace. We recognize that this goal is a significant undertaking and are working hard to make this a sustainable reality.

To help us achieve this goal, significant effort was undertaken to establish the Hydro One Health, Safety and Environmental Management System. This system is based on international standards for occupational health and safety management systems and environmental management systems. We plan to have this new system fully implemented in 2003.

Several programs and practices have been implemented to improve our safety performance. One example is our rigorous compliance review program. This program makes it a requirement for us to continually examine the work practices we have in place, and take corrective actions where there is room for improvement. Emphasis on work site inspections and effective job planning are also contributing to a safer workplace by identifying hazards and ensuring that proper barriers are in place before work is undertaken.

Another factor that contributed to improved safety performance was the restructured joint union and management health and safety committees, whose full impact was felt this year for the first time. These committees now deal with the health and safety issues for a specific trade in a particular region of the province. These committees provide a forum for more specific feedback on how to improve health and safety for particular trades, making their impact more effective.

IN THE EYE OF THE STORM



This year was extraordinary in many ways for Hydro One, and the challenges faced by our front line crews were no exception.

Ontario experienced 31 major storms in 2002, compared with 13 the year before. This resulted in $50 million being spent to repair storm damage to Hydro One's distribution lines in 2002, four times as much as the previous year.

Field staff worked a total of 284,000 hours on storm damage in 2002, more than three times the 70,000 hours they worked in 2001.

Our front line crews' quick and effective work was demonstrated during the severe storm that hit Northwestern Ontario on June 10. This weather disturbance was accompanied by winds of more than 100 kilometres per hour and rains so severe that heavy flooding washed out roads. The storm left about 15,000 customers without power and made restoration work challenging.

In response, Hydro One mobilized its crews from Timmins and North Bay, as well as crews from local distribution companies. In total, 160 employees worked to restore power to most customers by June 12 under very difficult circumstances.

New technology hits the field

To enable our employees to perform their jobs in the field more effectively and efficiently, we introduced new technology last year to help them report on the condition of our assets. Accurate and timely information about the condition of those assets is essential for Hydro One to make investment planning decisions that will ensure those assets continue to reliably deliver the province's electricity.

And the more comprehensive and timely the information collected in the field, the more cost-effective those investment planning decisions will be — investing in those assets that need it at the optimum time of their working life.

To increase the accuracy and ease of collecting the necessary information, our employees have begun using mobile information technology devices in the field. This technology increases productivity by allowing them to enter data on the spot and upload it to a computer system that makes their findings available to our asset managers almost immediately.

For example, our employees used this new technology to become more efficient at testing the condition of our utility poles. With more than 1.6 million utility poles in Ontario, there's a clear financial incentive for accurately assessing their condition on an ongoing basis.

Each year, our employees test a percentage of the poles to determine whether they need to be replaced. This year, using a handheld computing device, our employees were able to test more than 120,000 poles. So successful was this pilot project that plans are underway to introduce the same kind of technology for collecting data on other assets.

Meter Reader Allison Gibson

Innovation increased productivity and safety

In 2002, Hydro One employees developed and implemented new methods of performing front line operations that will lead to more effective use of our resources, as well as cost savings.

Work began this year on a project designed to optimize the routes our 123 meter readers follow each day, providing a more logical flow of routes and eliminating scheduling inefficiencies. When the redesigned routes are put into place in the summer of 2003, we will save an estimated $2 million each year.

To improve productivity, employees must have access to the latest training in their particular field, so we continued to invest in the development and maintenance of our trades and technical workers' skills during 2002. The result was more than 3,000 trades and technical training courses being delivered to 25,000 participants.

Successfully delivering these kinds of apprenticeship programs to an organization composed of such a diverse workforce spread over such a wide geographic area requires innovative teaching methods. We designed the training program to be delivered in a number of adaptable ways, including self-paced, instructor-taught and Web-based methods.

As proof of our success in this area, we won the contract to deliver our apprenticeship training to other Electricity Distributors Association member utilities. Employees of local distribution companies all over the province will now have access to the same high quality, safety-focused apprenticeship training available to Hydro One employees.

In addition, our field crews continued to develop innovative new tools this year to help them do their job more efficiently, while allowing them to perform their tasks more safely.

Our Station Services group developed a prototype for a copper grounding stud that allows them to perform work on a station that does not have permanent grounding. The new copper stud, which will be produced in 2003, is a more safe and efficient temporary grounding tool that can be grounded directly to vehicles and structural steel with one easily applied bolt.

In the past, work crews used a commercially manufactured grounding tool that required more bolts and could handle only a limited amount of current. In contrast, the new tool can handle much more — 70,000 amps at 25 cycles, the equivalent of a lightning strike.

Doing what we do responsibly: Reaching out to communities

At Hydro One we know that being the best in our business is not just about electrons and wires — it's also about contributing to the quality of life in the communities we serve, and where our employees and our customers live and work.

Getting a safety message out

As the largest transmission and distribution system in Ontario, Hydro One has a key role to play in promoting electrical safety in the home, school and workplace through education and public awareness. This year, we made a significant investment in public safety awareness, through sponsorships, donations and outreach programs.

Because electrical safety affects everyone, Hydro One's public safety initiatives target a wide range of audiences — from industry players to commercial operations to schoolchildren. Ultimately our programs are designed to reduce the number of potential electrical injuries in the province.

This year, for example, one of our safety campaigns was aimed at construction contractors, a group experiencing a high incidence of contact with overhead power lines in the course of their daily use of heavy construction equipment. Material published in trade journals illustrated some common scenarios and sent a strong message describing the safe work practices to follow to reduce the potential for injury.

Our commitment to public safety also included many educational and outreach initiatives in 2002. We visited more than 325 elementary schools across Ontario, delivering safety education to young children, through our own electrical safety presentations and our partnership with the O.P.P. Bearhug Band.

Involved in the communities we serve

Our involvement in the life and well-being of our communities goes beyond mounting public safety initiatives. It also includes taking an active role in local volunteer programs and donating to local charities.

This year, we donated $203,000 to support the operation of Sunnybrook Hospital's Northern Ontario Remote Telecommunications Health (NORTH) Network. NORTH Network connects medical practitioners in many hospitals across Ontario to specialists at Toronto's Sunnybrook Hospital through two-way medical conferencing, allowing them to diagnose and treat people in their own communities.

Hydro One Networks' operations centres will relocate to Barrie

Centralizing Operations Function

Hydro One has made use of new advances in technology to streamline operations and deliver the same or better levels of service across the province.

A major initiative has been the construction of a new state-of-the-art operating centre, located in Barrie. Staff have already begun migrating to this new centre, which is scheduled to be fully operational by May 2004. From this one central location, about 210 employees will be responsible for running Hydro One's entire distribution and transmission system, down from the 320 staff required to run the system under the decentralized model.

The more sophisticated technology at the Barrie centre will help us better manage our networks. In addition, with employees who perform similar functions all located in one centre, there will be enhanced opportunities for ongoing training and information-sharing. By consolidating a number of regional operating centres into the single operating location, we will also be able to reduce costs, improve operating performance, and enhance customer satisfaction.

Our donation was directed to the development and implementation of a new electrical burn program. Because electrical burns are a misunderstood injury, it's important that victims get the appropriate treatment during the critical first few hours and beyond. Our donation helps ensure that no matter where people are in the province, they now have timely access to the appropriate medical treatment.

Our annual Charity Trust campaign enables our employees and pensioners to give back to their own communities. This year, the campaign raised more than $640,000, which our employees designated to more than 800 charities across the province.

Our relationship with the aboriginal communities in the province is a critical element in our overall community outreach effort. This year we signed a long-term agreement with the Wahta Mohawks that resolved longstanding grievances over land use. It was a significant achievement that secured access to a strategic section of our transmission lines.

In addition, we introduced an aboriginal training manual and rolled out workshops for employees on aboriginal relations. This initiative is designed to help our employees to continue to work effectively with aboriginal communities.

Bill Reesor is among the more than 90,000 farm customers served by Hydro One Networks.

Hydro One is proud to support community amateur sport. Pictured is Ryan Fagen of the Markham Lightning.

Clearing branches away from power lines helps to ensure system reliability. Pictured is Kim Meeker, Regional Maintainer – Forestry.

Exceeding our environmental goals

As the largest wires company in Ontario, we have assets that stretch across all regions of the province. For that reason, we take our role as responsible stewards of the environment very seriously. This year we made significant progress in implementing new tools and programs to help us continue to meet this commitment.

In 2002, Hydro One Remote Communities, our subsidiary responsible for the generation and distribution assets used by 19 remote communities across northern Ontario, achieved ISO 14001 registration for its environmental management system. Attaining this designation came with great effort and dedication and demonstrates the commitment Hydro One Remote Communities has to better manage the impact of its activities on the environment and follow sound environmental practices.

Hydro One as a whole performed better than planned on our environmental performance index, which is a composite measure of five different environmental indicators. Ultimately, this means that we performed our work while placing a strong emphasis on environmental protection. One of the key reasons for this encouraging result is that environmental considerations are an integral part of all decision-making at Hydro One

Hydro One's land assessment and remediation program is designed to prevent any contaminated sites under our control from posing health and environmental hazards or business liabilities. Starting in 1998, we implemented an extensive program of site assessments, and, where appropriate, remediation.

In 2002, we conducted 93 detailed environmental site assessments and completed remediation or implemented site management plans at 37 locations across the province.

We're proud to report that the Ministry of the Environment has advised that Hydro One has met all requirements related to the Ministry of the Environment Director's Order that was issued to the former Ontario Hydro in 1997. The Order required us to perform environmental site assessments at certain of our remote generating stations and generating station switchyards.

Hydro One is committed to becoming a PCB-free utility. In 2002, we identified and replaced over 400 PCB-contaminated distribution transformers. Approximately 163 tonnes of low-level PCB material, which includes PCB-contaminated mineral oil and spill clean-up material, were taken out of service and 276 tonnes were destroyed. We continue to maintain our PCB storage sites in accordance with strict provincial regulations.

Ready for the future

We've come a long way in a short period of time. In the four years since our company was created, we've developed and executed a strategy that positions us to create value for our shareholder in the delivery of electricity to meet Ontario's needs now, and in the future.

We took a critical look at our business, and acted decisively to ensure a clear focus on the delivery of electricity within the province of Ontario. We will continue to excel because of our commitment to safeguarding the public and our employees from the hazards inherent in our business, a dedication to operational excellence and customer service, and our will to forge strong relationships with the communities where we work and live.

A class act

2002 Summer Student Chuong Tieu

For Chuong Tieu, securing a position through Hydro One's summer student program was more than just a part-time job — it was a way to help his family out of a difficult situation and put himself on the path to his chosen career.

Tieu's father had recently passed away, and the 19-year-old realized he needed to step forward to support his family and pay his own way through school.

Tieu, a student at Jarvis Collegiate in inner city Toronto, was one of four summer students chosen as part of Hydro One's pilot outreach program. The program is designed to provide sought-after summer jobs to Ontario high school students who might not normally have the opportunity to obtain this type of employment. Hydro One plans to extend the outreach program to all of its locations, accounting for 20% of summer student hiring in 2003.

Now in the first year of the mechanical engineering program at Ryerson University, Tieu credits his Hydro One job with helping him fund his educational dream.

"It was a once-in-a-lifetime opportunity," says Tieu. "Everyone was very friendly and helpful."

Financial Review

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Five-Year Summary of Financial and Operating Statistics

Management's Discussion and Analysis

This discussion contains forward-looking statements that are subject to risks, uncertainties and assumptions. Such information represents our current views based on information as at the date of this report. We do not intend to update this information and disclaim any legal obligation to the contrary.

We prepare our financial statements in Canadian dollars and in accordance with accounting principles generally accepted in Canada, (Canadian GAAP), which differs in some respects from accounting principles generally accepted in the United States (U.S. GAAP). See Note 22 to the Consolidated Financial Statements for the three years ended December 31, 2002. The following discussion is based upon our Consolidated Financial Statements prepared in accordance with Canadian GAAP, except as otherwise indicated.

OVERVIEW

Since the date of incorporation, the Province of Ontario (the Province) has owned all of our outstanding shares. Throughout 2002, the Province considered and investigated ownership options for our company. On March 28, 2002, we filed a preliminary prospectus in Canada and a registration statement on Form F-1 in the United States in contemplation of the sale of our outstanding common shares by the Province. These documents were officially withdrawn on June 17, 2002. The Province subsequently launched a process to seek a strategic partner or partners for a minority interest in our company. On January 20, 2003, the Province announced it would continue to retain all of the outstanding shares of our company.

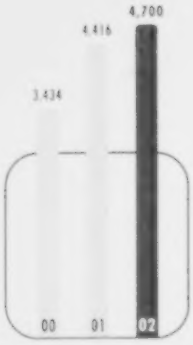
Total Assets
December 31
(Cdn $ millions)

Based on assets as at December 31, 2002, our transmission system is one of the largest in North America and our distribution system is the largest in Ontario. In 2002, our transmission and distribution businesses generated approximately 35% and 66%, respectively of our total revenues and approximately 78% and 27%, respectively of our income before financing charges and provision for payments in lieu of corporate income taxes. The contribution to revenues of our distribution business is significantly higher than the contribution to the revenues of our transmission business because distribution revenues include recovery for electricity used by our customers.

Transmission Assets
December 31
(Cdn $ millions)

Transmission

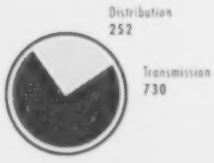
Our transmission business, which represented approximately $6.6 billion of our assets as at December 31, 2002, transmits electricity through an approximately 28,500 circuit-kilometre high-voltage transmission network which we own as well as operate. We transmit electricity from generators to local distribution companies, including our own distribution system and industrial customers with a direct connection to our transmission system. In addition, we own and operate 26 facilities that inter-connect our transmission system with transmission systems in neighbouring provinces and states.



Distribution Assets
December 31
(Cdn $ millions)

Distribution

Our distribution business, which represented approximately $4.7 billion of our assets as at December 31, 2002, distributes electricity through our approximately 123,000 circuit-kilometre low-voltage distribution system to approximately 1.2 million rural and urban customers, and commercial, industrial and local distribution companies that are not directly connected to our high-voltage transmission system. Our distribution service territory includes all of Ontario, excluding the service territories of the 97 local distribution companies that we do not own. Since April 1999, we have acquired 89 local distribution companies that we now operate as part of our distribution business. We also operate generation and distribution systems in 19 remote communities across northern Ontario that are not connected to Ontario's electricity grid.



2002 Regulated Operating Income
Year ended December 31
(Cdn $ millions)

Other

Our other businesses, which represented approximately $90 million of our assets as at December 31, 2002, involve the marketing of our fibre-optic capacity to telecommunications carriers and commercial customers. This segment also included our energy services business conducted by our wholly owned subsidiary, 1316664 Ontario Inc., formerly Ontario Hydro Energy Inc. (Ontario Hydro Energy). Effective April 30, 2002, we sold the competitive retail operations of this subsidiary and we are currently in the process of winding up its remaining operations (See Note 5 to the Consolidated Financial Statements).

Revenues and Costs

We earn transmission revenues based on the peak demand for electricity across our high-voltage network. We earn distribution revenues based on a fixed periodic service charge combined with a variable charge that reflects the consumption of electricity by our distribution customers. The rates that we charge are subject to the decisions of the Minister of Energy and our regulator, the Ontario Energy Board (OEB). Distribution revenues include recovery for electricity used by our customers, the cost to deliver the electricity and related services to customers in our service territory.

Purchased power costs incurred in our distribution business primarily represent the cost of electricity delivered to customers within our distribution service area.

Hydro One Executive Committee

« Left to Right

Glen Wright
Chair

Tom Parkinson
President and Chief Executive Officer

Laura Formusa
Secretary and General Counsel

Ken Hartwick
Chief Financial Officer

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. In addition, these costs include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Depreciation and amortization expense primarily includes depreciation of our fixed assets in service and amortization associated with our regulatory assets.

Financing charges primarily consist of interest expense associated with our debt.

Since April 1, 1999, we have been making payments in lieu of corporate income taxes to Ontario Electricity Financial Corporation (OEFC) in accordance with the *Electricity Act, 1998* on the same basis as if we were subject to federal and provincial corporate taxes. We provide for payments in lieu of corporate income taxes relating to our regulated businesses using the taxes payable method as directed by the OEB.

REGULATION

Our industry has undergone significant restructuring initiated by the Province over the past several years. Under the *Electricity Act, 1998*, as of April 1, 1999, the businesses of Ontario Hydro were reorganized into five separate corporations, including our company which, through wholly owned subsidiaries, operates as the successor to Ontario Hydro's electricity transmission, distribution and energy services businesses. This restructuring was in anticipation of Ontario's wholesale and retail electricity markets becoming open to competition, which officially occurred on May 1, 2002 (Open Access). On December 9, 2002, the Province enacted the *Electricity Pricing, Conservation and Supply Act, 2002 (Bill 210)*, which amended the *Electricity Act, 1998* and other statutes for the purpose of implementing the Electricity Action Plan announced by the Premier of Ontario on November 11, 2002.

Transmission and Distribution Rates

Rates for our transmission business for periods preceding Open Access were set by the OEB to provide for an annual rate of return of 9.88% on the amount of common equity deemed to be allocated to this business. During this period, our company did not bill customers directly for transmission services. Instead, regulated transmission revenues were collected by Ontario Power Generation Inc. (OPG) and paid to us pursuant to a revenue allocation agreement among the successor corporations. The revenue allocation agreement ceased upon Open Access and the Independent Electricity Market Operator (IMO) now remits payments to us based on the uniform transmission rates approved by the OEB for all transmitters across Ontario. Based on our estimated load, these rates were also set to provide for an annual rate of return of 9.88%.

Prior to Open Access, our distribution business purchased power on a fixed-price basis from OPG and charged our distribution customers a bundled rate for the generation, transmission and distribution of electricity. The bundled rates originally set by the OEB for 2000 provided for an annual rate of return of 9.88% on the amount of common equity deemed to be allocated to our distribution business. Bundled rates remained in place until Open Access.

During 2001 the wholesale cost of power to us was increased on two occasions. Effective June 1, 2001, the Province passed a regulation that increased to all distribution companies, including ours, the wholesale cost of power supplied by OPG by 0.7 cents per kWh. The OEB approved the incorporation of this non-distribution-related increase into customers' bundled rates. The wholesale cost of power to our distribution business was further increased by 1.15 cents per kWh effective October 1, 2001 so that after such increase our cost of power was consistent with the rate paid by other large distributors. On January 19, 2001, we applied, through Hydro One Networks Inc. (Hydro One Networks), to reduce the retail portion of our distribution revenue requirement which would have been effective October 1, 2001, from approximately $742 million to $646 million to substantially mitigate the impact on our customers of this increase in our cost of power, with this mitigation to be partially phased out over a three-year period. We commonly refer to this mitigation as our rate mitigation plan.

Commencing with Open Access, we purchase power from the IMO administered spot market and charge our distribution customers unbundled rates, including our OEB-approved distribution rates. These distribution rates are essentially the same as the distribution rates that were incorporated into bundled rates before Open Access.

On August 30, 2002, the OEB issued a rate order establishing unbundled distribution rates; this order reflected the OEB's June 12, 2002 decision regarding our application that we filed on January 19, 2001. The OEB approved an overall distribution revenue requirement (including that from retail rates, low voltage rates and miscellaneous charges) of $646 million effective October 1, 2001, $694 million effective March 1, 2002 and $742 million effective March 1, 2003. In addition, the OEB confirmed the interim approval for the recovery of approximately $8 million toward costs incurred to align our business systems and practices with the requirements of the competitive electricity market, commonly referred to as market ready costs.

Electricity Pricing, Conservation and Supply Act, 2002

Bill 210 was enacted for the purpose of implementing the Electricity Action Plan announced by the Premier of Ontario on November 11, 2002. The more significant provisions of Bill 210 for our transmission and distribution businesses are as follows:

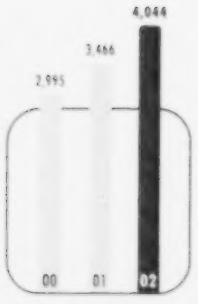
- Energy prices for low volume and designated consumers (as defined in Bill 210) are fixed at 4.3 cents per kWh, retroactive to May 1, 2002. Most of our distribution customers (who consume, in the aggregate, approximately 70% of the energy we distribute) qualify for the fixed energy price. In recognition of commodity prices in excess of 4.3 cents per kWh for the period from May 1, 2002 to December 1, 2002, Bill 210 required distributors to issue a $75 refund to eligible consumers and to credit any remaining refund on future bills. The IMO has, and will continue to facilitate this price freeze through funding from OEFC, and accordingly we have reduced our distribution revenues and purchased power costs reported to the end of the third quarter of 2002 by $91 million, representing an increase of $22 million in the second quarter and a decrease of $113 million in the third quarter.

- Transmission and distribution rates are capped until at least April 30, 2006. A rate application can be made to the OEB before this date with the written approval of the Minister of Energy. Any rate increases that had been approved by the OEB but not implemented by December 1, 2002 were suspended. As a result, the March 1, 2003 increase and the rate changes associated with low-voltage charges for embedded local distribution companies and direct customers cannot be implemented. The $8 million increase in distribution revenues associated with market ready costs that was approved by the OEB for the 10 months starting May 1, 2002 will remain in rates until at least April 30, 2006.

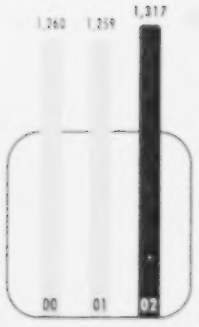
- Effective December 1, 2002, the price paid by distributors to the IMO for wholesale market charges other than energy is largely fixed at the same price distributors are permitted to charge their customers. For the period May 1, 2002 to December 1, 2002, differences between the rates were accumulated in retail settlement variance accounts under the provisions of Article 490 in the OEB's *Accounting Procedures Handbook* for disposition through future offsetting variances or through approved rate adjustments.

- Bill 210 provides for the establishment or continuation of deferral accounts for certain amounts until disposition is addressed by the OEB. For our company, the most significant accounts include: the retail settlement variance accounts, market ready costs, and the revenue we would have billed had the low voltage facilities charges approved for embedded local distribution companies and direct customers been implemented. Bill 210 also provides for the continuation of a deferral account for the environmental remediation costs incurred by our distribution business in 2001 and 2002. The accounting treatment for these environmental costs was reviewed with the OEB as part of our rate mitigation plan.

The enactment of Bill 210 also effectively capped rates for both Hydro One Remote Communities Inc. (Hydro One Remote Communities), through which we service remote communities across northern Ontario, and Hydro One Brampton Inc. (Hydro One Brampton), which we acquired in 2001. All other local distribution companies that we purchased have been fully integrated within Hydro One Networks, our primary operating subsidiary. As a result of the rate cap, Hydro One Remote Communities' rate of return continues to reflect a 100% debt financed capital structure and Hydro One Brampton will not be able to implement the final rate increase to be able to achieve a 9.88% return on equity as originally proposed by the OEB.



Revenue
Year ended December 31
(Cdn $ millions)



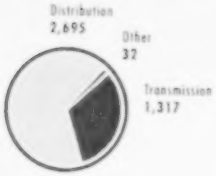
Transmission Revenue
Year ended December 31
(Cdn $ millions)

RESULTS OF OPERATIONS

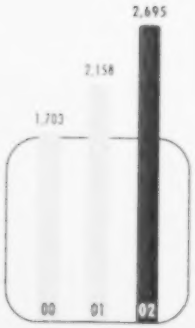
Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Revenues

Transmission. Transmission revenues increased by $58 million, or 5%, to $1,317 million in 2002. This higher revenue level reflects the increased peak usage of electricity caused by the unusually hot weather conditions that were primarily experienced in the second and third quarters of 2002.



2002 Revenue
Year ended December 31
(Cdn $ millions)



Distribution Revenue
Year ended December 31
(Cdn $ millions)

Distribution. Distribution revenues increased by $537 million, or 25%, to $2,695 million in 2002. This increase principally reflects the volume of electricity we distributed through our system this year. Higher revenues of $537 million were attributable to acquisitions of local distribution companies in 2001, including Hydro One Brampton which we purchased on July 31, 2001, and a new requirement to directly serve a number of commercial, industrial and local distribution companies that are connected to our low voltage system. Prior to the opening of the electricity market to competition on May 1, 2002, these customers purchased their electricity from OPG. Volume further increased as a result of weather related demand. After reducing our distribution revenue to reflect the commodity price of 4.3 cents per kWh for approximately 70% of the energy we distributed since May 1, 2002 as stipulated in Bill 210, the increase in revenues from commodity, associated charges and distribution rates was $51 million. This amount includes the impact of the OEB-approved rate changes effective October 1, 2001 and March 1, 2002. These increases in revenue from the sale and delivery of electricity were partially offset by reductions totaling $51 million in other revenue, including revenue attributable to the revenue allocation agreement that was in effect until Open Access and to non-energy services.

Other. Other revenues declined by $17 million to $32 million in 2002. These results primarily reflect the sale of substantially all of the assets pertaining to our competitive retail operations, effective April 30, 2002. See Note 3 to the Consolidated Financial Statements.

Purchased Power

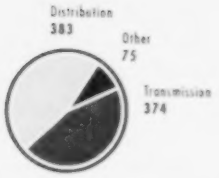
Purchased power costs increased by $604 million, or 48%, to $1,871 million in 2002. Purchased power costs increased by $498 million due to volume, including the acquisitions of local distribution companies, the additional customers that we are now required to directly serve and the weather related demand. After reducing purchased power costs to reflect the commodity price of 4.3 cents per kWh, purchased power costs further increased by $106 million as a result of commodity and associated charges. This amount includes the impact of the regulations passed by the Province, as discussed above under "Regulation", that effected two increases in the wholesale cost of power during 2001.

Operation, Maintenance and Administration

Total operation, maintenance and administration costs increased by $8 million, or 1%, to $832 million in 2002, due to the factors discussed below.

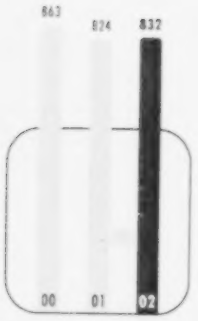
Transmission. Transmission operation, maintenance and administration costs increased by $20 million, or 6%, to $374 million in 2002. Expenditures necessary to operate and support our transmission system increased by $24 million as a result of the costs incurred to amalgamate the remaining operating centres as well as the costs associated with an initiative to further reduce staff levels. See "Staff Reduction Program" described below. This increase was partially mitigated by a reduction of $4 million in costs to sustain our transmission system. Lower costs required to support our power equipment maintenance and site infrastructure programs were partially offset by higher corrective maintenance costs on our overhead lines due to weather conditions.

Distribution. Distribution operation, maintenance and administration costs declined by $8 million, or 2%, to $383 million in 2002. Expenditures necessary to operate and support our distribution system declined by $12 million due to a reduction in one-time costs to integrate the acquired utilities and lower costs to support non-energy services, partially offset by costs associated with an initiative to further reduce staff levels. See "Staff Reduction Program" described below. This reduction was further offset by an increase of $4 million in costs incurred to sustain our distribution system. Higher costs were incurred primarily to respond to increased customer trouble calls caused mainly by weather conditions and to service our larger territory, including that of Hydro One Brampton. These costs were substantially offset by a reduction in the vegetation management program.



2002 Operation, Maintenance and Administration
Year ended December 31
(Cdn $ millions)

Other. Other operation, maintenance and administration costs declined by $4 million, or 5%, to $75 million in 2002. These results primarily reflect the sale of substantially all of the assets pertaining to our competitive retail operations and the costs associated with winding up the remaining operations of the former Ontario Hydro Energy. See Note 3 to the Consolidated Financial Statements.



Operation, Maintenance and Administration
Year ended December 31
(Cdn $ millions)

Staff Reduction Program. In September 2002, we announced that staff levels would be reduced by approximately 140 employees, primarily from head office managerial and managerial support functions. The reduction, which is expected to result in ongoing savings of approximately $16 million per annum, was achieved by using voluntary and involuntary measures, including those available under collective agreements for some of the affected employees. A provision of $25 million has been charged to the results of operations for the estimated cost of achieving the staff reduction. See Note 4 to the Consolidated Financial Statements.

Depreciation and Amortization

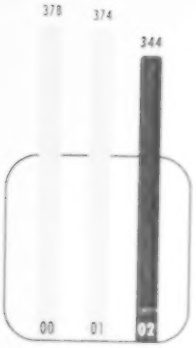
Depreciation and amortization expense increased by $27 million, or 7%, to $411 million in 2002. Depreciation expense increased by $20 million primarily due to the acquisitions of local distribution companies during 2001 as well as to in-service additions arising from our capital expenditure program. Amortization expense increased by $7 million primarily due to the amortization of the regulatory asset established for market ready costs.

Financing Charges

Financing charges increased by $3 million, or 1%, to $353 million in 2002. This increase reflects higher average levels of debt, partially offset by the impact of lower interest rates incurred on the debt outstanding.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes decreased by $34 million, or 13%, to $233 million in 2002. This reduction primarily reflects lower levels of income and a reduction in the statutory tax rate from 41.74% in 2001 to 38.62% in 2002. The impact of these reductions was partially offset by temporary differences, including the 2002 charge for the staff reduction program. This charge for the staff reduction program was recognized for accounting purposes in 2002, but will be deducted for tax purposes when the related cash payments are made.



Net Income
Year ended December 31
(Cdn $ millions)

Net Income

Net income decreased by $30 million, or 8%, to $344 million in 2002. This reduction in net income primarily reflects the phasing in of the October 1, 2001 increase in the wholesale cost of power to our distribution business into customer rates. This reduction in the distribution revenue requirement was put forward to help offset the impact on our customers of the October 1, 2001 increase in our wholesale cost of power. The impact of this reduction in our revenue requirement was partially offset by the higher transmission and distribution revenues experienced from volume attributable to the hot weather conditions experienced in the second and third quarters of 2002.

Reliable Energy and Consumer Protection Act, 2002

On June 27, 2002, the Province passed the *Reliable Energy and Consumer Protection Act, 2002* (the Act) that amends several statutes relating to Ontario's energy sector, including the ownership and use of corridor land. Corridor land includes land in Ontario owned by our company that was used or acquired for the purposes of the transmission system, including any abutting land. Under the Act, ownership of all corridor and abutting land was transferred to the Province and we were given the right to use the land to operate the transmission system. We also retain the obligation to incur certain ongoing expenditures related to our use of this land, including maintenance, property taxes and any future environmental remediation work that may be required by the Province. The OEB is authorized to restrict or discontinue any use of the corridor land that interferes with the transmission system.

The transfer of the corridor land was effective December 31, 2002, resulting in ownership of transmission corridors and abutting lands with a net book value of approximately $259 million being transferred to the Province in exchange for an indefinite rights of use asset. In addition, ownership of land assets with a net book value of approximately $7 million, not currently in use, was transferred to the Province and applied as a reduction of shareholder's equity.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Revenues

Transmission. Transmission revenues declined by $1 million to $1,259 million in 2001. Tariff revenues increased by $31 million, or 3%, in 2001 as a result of transmission load growth in accordance with the revenue allocation agreement. This increase was offset by a decline in non-energy related service revenues of $32 million as a result of substantial one-time revenues recorded in 2000 relating to contract work preparing other industry participants for Open Access.

Distribution. Distribution revenues increased by $455 million, or 27%, to $2,158 million in 2001. Revenues from the sale and delivery of electricity increased by $344 million, of which $268 million was attributable to the acquisitions of local distribution companies. In addition, revenues were higher as a result of the two rate increases related to the wholesale cost of power. The June 1, 2001 rate increase accounted for a $93 million rise in distribution revenues and the October 1, 2001 rate increase accounted for an additional $18 million.

Other. Other revenues increased by $17 million, or 53%, to $49 million in 2001. Energy services revenues increased by $10 million primarily due to increased sales of ancillary residential services. Substantially all of the assets pertaining to our competitive retail operations were sold effective April 30, 2002. See Note 3 to the Consolidated Financial Statements. Revenues from our telecommunications business increased by $7 million, primarily from sales of dark fibre capacity to major carriers.

Purchased Power

Purchased power costs increased by $408 million, or 47%, to $1,267 million in 2001. The increase attributable to acquisitions and volume growth totaled $265 million, including $211 million attributable to acquisitions of local distribution companies. In addition, as discussed above under "Regulation", the Province passed regulations effecting two increases in the wholesale cost of power during 2001. The June 1, 2001 and October 1, 2001 increases and a change in the pricing methodology of OPG resulted in higher purchased power costs totaling $143 million.

Operation, Maintenance and Administration

Total operation, maintenance and administration costs declined by $39 million, or 5%, to $824 million in 2001, due to the factors discussed below.

Transmission. Transmission operation, maintenance and administration costs declined by $79 million, or 18%, to $354 million in 2001. Expenditures necessary to sustain our transmission system, including preventive and corrective maintenance on transformer stations, transmission lines and telecommunications equipment, declined by $17 million. In addition to achieving a full year of savings in 2001 as a result of the substantial completion of a staff reduction program in 2000 which was initiated in 1999 (1999 staff reduction program) we embarked on a number of initiatives to enhance productivity, such as improving labour utilization. Key initiatives to improve labour utilization included a hiring hall established with the Power Workers' Union to provide staffing flexibility and the use of temporary headquarters to reduce travelling time for our line and forestry crews. Expenditures to operate and support our transmission system declined by $24 million, primarily as a result of the 1999 staff reduction program. In addition, costs incurred to provide non-energy-related services declined by $38 million due to the substantial completion of work in 2000 for other industry participants in preparation for Open Access.

Distribution. Distribution operation, maintenance and administration costs increased by $3 million, or 1%, to $391 million in 2001. Costs incurred to sustain our distribution system, including our remote system, which are related primarily to customer trouble calls to restore power, vegetation management and line and station maintenance work, increased by $38 million. We also incurred an additional $13 million in one-time operation, maintenance and administration costs to integrate acquired local distribution companies. We achieved a reduction of $48 million in costs to operate and support our distribution system, primarily from the 1999 staff reduction program as well as productivity initiatives similar to those of our transmission business.

Other. Other operation, maintenance and administration costs increased by $37 million to $79 million in 2001. This increase was primarily associated with the growth of our telecommunications business and our energy services business. Substantially all of the assets pertaining to our competitive retail operations were sold effective April 30, 2002. See Note 3 to the Consolidated Financial Statements.

Depreciation and Amortization

Depreciation and amortization expense increased by $36 million, or 10%, to $384 million in 2001. Depreciation expense increased by $30 million primarily due to the acquisitions of local distribution companies as well as to our expanded capital expenditure program. Amortization expense increased by $6 million, of which $5 million was due to the amortization of the regulatory asset recorded effective January 1, 2001 for the recovery of costs required to remediate past environmental contamination and $1 million was due to the amortization of goodwill related to the acquisitions of local distribution companies.

Financing Charges

Financing charges increased by $10 million, or 3%, to $350 million in 2001. This increase principally reflects higher average levels of debt.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes increased by $60 million, or 29%, to $267 million in 2001. This increase reflects higher levels of income and lower available tax deductions, partially offset by a reduction in the statutory tax rate from 43.95% in 2000 to 41.74% in 2001. Lower tax deductions were primarily attributable to the absence in 2001 of tax deductions available in 2000 related to the 1999 staff reduction program and capital cost allowance deductions. Tax deductions related to the staff reduction program were primarily taken in 2000 when the related cash payments were made.

Net Income

Net income decreased by $4 million, or 1%, to $374 million in 2001. This reduction in net income primarily reflects a higher provision for payments in lieu of corporate income taxes from lower available tax deductions, partially offset by an increase in contribution from higher electricity sales. The increase in contribution attributable to higher electricity sales volume was reduced by the revenue shortfall resulting from the phasing-in of the October 1, 2001 increase in the wholesale cost of power to our distribution business into customer rates.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2001 through December 31, 2002. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and includes all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	2002				2001			
Quarter ended	Mar. 31	Jun. 30	Sep. 30	Dec. 31	Mar. 31	Jun. 30	Sep. 30	Dec. 31
Total revenues[1]	**1,022**	**910**	**1,131**	**981**	816	722	880	1,048
Net income	**106**	**99**	**112**	**27**	134	114	103	23
Net income to common shareholder	**101**	**95**	**107**	**23**	129	110	98	19

[1] Total revenues have been restated from amounts presented for the quarters subsequent to May 1, 2002 to reflect the fixed commodity price stipulated by Bill 210 of 4.3 cents per kWh for low volume and designated customers. As purchased power was revised by the same amount, there was no impact on net income and net income to common shareholder.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity and Capital Resource Requirements

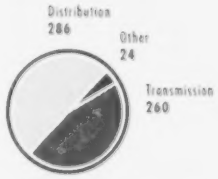
Our principal liquidity and capital resource requirements consist of the following:

- capital expenditures to maintain, improve and expand our transmission and distribution assets;
- servicing and repayment of our debt;
- outsourcing arrangement;
- investing activities; and
- dividends.

Capital Expenditures

Our total capital expenditures amounted to $570 million in 2002, representing an increase of $4 million over spending levels of $566 million in 2001. Capital expenditures in 2001 were $120 million higher than 2000 levels of $446 million. These amounts exclude capital expenditures associated with acquisitions of local distribution companies of $468 million in 2001 and $23 million in 2000. We did not acquire any material local distribution companies in 2002.

Transmission. Capital expenditures for our transmission business were $260 million, $274 million and $280 million in 2002, 2001, and 2000, respectively. Capital expenditures on transmission stations, lines, equipment and telecommunications refurbishment were $145 million in 2002, lower than spending levels in 2001 and 2000 of $184 million and $183 million, respectively. The decrease in 2002 relative to 2001 was primarily due to efficiencies associated with the replacement of our microwave radio system, as well as some deferrals in proceeding with our station refurbishment program. In 2001, increased spending on telecommunications facilities for transmission was partially offset by lower pole replacement work compared to 2000. Capital expenditures incurred to expand our transmission system were $51 million, $60 million and $64 million in 2002, 2001 and 2000, respectively. The reduction in 2002 was caused by delays in proceeding with an interconnection project with Hydro Québec. This project was initiated to provide additional capacity of 1,250 megawatts between the two transmission systems. We are currently in the process of investigating options to advance this project or other interconnection projects. Capital expenditures supporting transmission operations increased to $64 million, compared to $30 million



2002 Capital Expenditures
Year ended December 31
(Can $ millions)

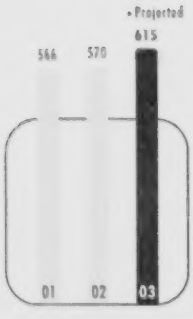
and $33 million in 2001 and 2000, respectively. The increased spending in 2002 was associated with the amalgamation of our operating centres, including the construction of an integrated facility through which we expect to achieve improved cost efficiencies, supply reliability and an enhanced level of service to our customers.

Distribution. Capital expenditures for our distribution business, excluding expenditures associated with acquisitions of local distribution companies, were $286 million in 2002, compared with $247 million and $152 million in 2001 and 2000, respectively. Customer-demand-driven capital expenditures increased to $141 million in 2002, compared with $114 million in 2001 and $79 million in 2000. The expansion of our service territory through acquisitions of local distribution companies has contributed to the increases since 2000. In addition, we further upgraded our system capacity in 2002. Capital expenditures incurred to sustain our distribution asset base amounted to $115 million in 2002, compared with $83 million and $34 million in 2001 and 2000, respectively. Spending requirements have increased since 2000 as a result of our expanded service territory and storm damage, which was particularly significant in 2002 as intense storms were experienced throughout the year. In 2001, our wood pole replacement program was also enhanced in response to an asset condition study. Capital expenditures supporting distribution operations declined to $30 million, compared to $50 million and $39 million in 2001 and 2000, respectively. The increased spending requirements in 2001 reflected the preparation of our systems and processes for Open Access.

Other. Capital expenditures for our other businesses amounted to $24 million in 2002 compared with $45 million in 2001, and $14 million in 2000. Expenditures in 2002 reflected minimal spending requirements for the energy services business, the impact of which was partially offset by the increased spending to support our emerging telecommunications business through the construction of a diverse fibre-optic network between Buffalo, Ottawa and Montreal. Increased expenditures in 2001 reflected the lighting of dark fibre in the Windsor, Fort Erie and Ottawa corridor, and the initiation of construction of the fibre-optic network between Buffalo, Ottawa and Montreal.

Future Capital Expenditures

In 2003, capital expenditures are budgeted at approximately $615 million, an increase of $45 million over our 2002 levels. The budgets for our transmission and distribution businesses are $335 million and $250 million, respectively. Other capital expenditures are budgeted at $30 million and are primarily related to the further enhancement of our fibre-optic network in support of our growing telecommunications business. We expect our capital expenditures to continue to remain relatively stable for the next few years.



Capital Expenditures
Year ended December 31
(Cdn $ millions)

Our 2003 capital budget for transmission and distribution includes the continuation of a number of major projects that are to be completed in 2004 and 2005, as well as the ongoing sustainment requirements of the transmission and distribution systems. In 2003, we will continue with the construction of the integrated operating centre to replace our eight territory operating centres which began last year, and will be completed in 2004. The major construction program for the integrated operating centre was completed in 2002 and, in 2003, staff relocation will begin as new

systems and tools are completed. The amalgamation of the two remaining operating centres will occur in 2004. Increased expenditures are also required for load customer connections and area supply adequacy which is in response to the IMO's assessment of the ability of existing and committed generation and transmission facilities to meet the needs of Ontario over the next ten-years. Investments in our distribution system will also continue to be made in new connections, upgrades and system capability reinforcements.

Servicing and Repayment of Our Debt

As at December 31, 2002, we had long-term debt outstanding of $4,579 million, including the current portion, with a weighted-average interest rate of 7.6%. Of this amount, $2,529 million is payable to OEFC and $2,050 million is publicly held. Outstanding short-term promissory notes amounted to $579 million with a weighted-average interest rate of 2.9%.

On January 24, 2003, we announced that OEFC intends to sell some or all of its Hydro One debt in the Canadian public debt markets, commencing early in 2003. The notes payable to OEFC mature between 2003 and 2007, with a weighted-average term to maturity of approximately two years. In order to facilitate the sale, we agreed in principle with OEFC to restructure some or all of the Hydro One debt held by OEFC.

On February 13, 2003, our Board of Directors approved the exchange of up to $1.9 billion of existing debt with a weighted-average interest rate of approximately 8% for up to approximately $2.15 billion of debt with a weighted-average interest rate of approximately 4%. This debt restructuring will result in lower cash interest payments for us from 2003 through 2007 and a corresponding increase in the principal amount of the debt payable at maturity. The maturity dates will remain essentially unchanged.

On January 28, 2003, we issued notes with a principal amount of $500 million under our medium term note program. The notes were issued in two tranches: a re-opening of Series 3 for $300 million at a coupon rate of 5.77% due November 15, 2012 and Series 4 for $200 million at a coupon rate of 6.35% due January 31, 2034. The total outstanding for Series 3 is now $600 million.

We plan to refinance debt maturing during 2003 and 2004 principally through our medium term note program. Our publicly held notes and debentures, including the debt financing completed on January 28, 2003, mature between 2005 and 2034.

Outsourcing Arrangement

On March 1, 2002, we commenced an outsourcing services agreement with Inergi LP (Inergi), an affiliate of Cap Gemini Ernst & Young Canada Inc. Under this agreement, Inergi provides, among other things, customer service operations, supply management, pay operations, information technology, and finance and accounting services over a ten-year term. As part of this outsourcing arrangement, approximately 900 of our employees were transferred to Inergi. The initial fee payable to Inergi will be approximately $130 million in the first full year of the contract declining to approximately $90 million in the tenth year of the agreement, net of inflation adjustments and subject to decreases based on external benchmarking analysis every three years. Because this outsourcing arrangement provides for a defined competitive and continuously improved price for the outsourced services, we believe that it will allow us to continue to reduce our cost base and improve our competitive position. As part of this agreement, we are still responsible for the capital expenditures associated with these services.

Investing Activities

Cash used for investing activities decreased by $470 million, or 46%, to $543 million in 2002 and increased by $475 million, or 88%, to $1,013 million in 2001, compared to the prior years. The level of expenditures in 2001 reflects the acquisition of the majority of the 89 local distribution companies that we have purchased since April 1, 1999. While we have not made any significant acquisitions in 2002, we spent $475 million in 2001 and $23 million in 2000 to acquire local distribution companies. Cash used for investing activities in 2002 also reflects proceeds of $50 million from the sale of substantially all of the assets pertaining to our competitive retail operations, effective April 30, 2002. See Note 3 to the Consolidated Financial Statements.

There are no specific acquisitions currently pending or under consideration. Any future transactions are not expected to be significant and we believe that we will have access to sufficient sources of liquidity and capital resources to complete such acquisitions.

Dividends

We paid dividends to the Province on our outstanding preferred shares and common shares totaling $192 million in 2002, $258 million in 2001 and $398 million in 2000. Dividends paid in 2000 include $171 million pertaining to 1999 that were paid in conjunction with the issuance of shares to the Province on March 31, 2000.

Our outstanding preferred shares are entitled to a total annual cumulative dividend of $18 million, payable on a quarterly basis.

The dividends on our common shares are declared at the discretion of our board of directors, and are recommended by our management based on our results of operations, financial condition, cash requirements and other relevant factors, such as industry practice and shareholder expectations. In 2002, dividends on our common shares in the amount of $174 million were declared, as compared with $240 million in 2001 and $371 million in 2000. Of the dividends declared during 2000, $158 million were declared in respect of the nine months ended December 31, 1999.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments.

December 31, 2002 (Canadian dollars in millions)	Total	2003	2004/ 2005	2006/ 2007	After 2007
Contractual Obligations *(due by year)*					
Short-term notes payable	579	579	—	—	—
Long-term debt[1]	4,579	651	1,189	889	1,850
Operating lease commitments	25	10	10	2	3
Inergi LP outsourcing agreement	919	120	216	199	384
Total contractual obligations	6,102	1,360	1,415	1,090	2,237
Other Commercial Commitments *(by year of expiry)*					
Bank line[2]	1,000	750	250	—	—
Letters of credit[3]	147	147	—	—	—
Guarantees[3]	275	275	—	—	—
Total other commercial commitments	1,422	1,172	250	—	—

[1] On January 28, 2003, we issued notes with a principal amount of $500 million under our medium term note program. The notes were issued in two tranches: a re-opening of Series 3 for $300 million at a coupon rate of 5.77% due November 15, 2012 and Series 4 for $200 million at a coupon rate of 6.35% due January 31, 2034. This debt financing is not reflected in the Summary of Contractual Obligations and Other Commercial Commitments as at December 31, 2002.

[2] As a backstop to our commercial paper program, we have a revolving standby credit facility with a syndicate of banks of $750 million for a 364-day term and $250 million for a five-year term.

[3] We currently have bank letters of credit of $97 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IMO as required by the Market Rules, using a combination of bank letters of credit of $50 million and parental guarantees of $275 million. The amount of prudential support that we provide in the form of bank letters of credit to the IMO is dependent on our long-term credit ratings from major Canadian and U.S. rating agencies. For example, the amount of bank letters of credit provided would need to increase if our credit ratings deteriorated.

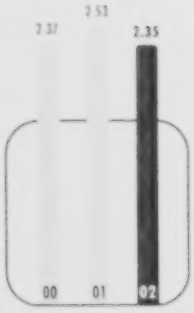
Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration costs on our statement of operations or in our capital programs. The amounts in the above table under short-term notes payable and long-term debt are not charged to our results of operations, but are reflected on our balance sheet and statement of cash flows. Interest associated with this debt is recorded under financing charges on our statement of operations or in our capital programs, but these financing charges are not reflected in the above table.

Sources of Liquidity and Capital Resources

Our primary sources of liquidity and capital resources are the following:

- funds generated from operations;
- debt capital markets borrowings; and
- bank financing.

2002 Capital Structure
December 31
(Cdn $ millions)



Earnings Coverage Ratio
Year ended December 31

Operating Activities

Net cash generated from operations was $492 million in 2002 compared with $914 million in 2001 and $725 million in 2000. The reduction of $422 million in 2002 reflects the increase in accounts receivable combined with the reduction in accounts payable and accrued charges. Since Open Access, our billing cycles have been delayed because commodity-billing rates are not available from the IMO until 10 working days after the end of each month, however we are still required to remit payment within 2 days of receiving our invoice for purchased power. Further, accounts payable and accrued charges have declined due to the reduction in our December invoice from the IMO for purchased power, which reflected the reduction to 4.5 cents per kWh for our low volume and designated customers, and a lower provision for payments in lieu of corporate income taxes.

The increase of $189 million in 2001 reflects significantly higher accounts payable and accrued charges, primarily from increases in the cost and volume of wholesale power, the operations of the acquired local distribution companies and higher provision for payments in lieu of corporate income taxes. The increase in accounts payable and accrued charges was partially offset by higher levels of accounts receivable from our electricity customers due to the increase in our customer base and the rate increases attributable to the wholesale cost of power.

Financing Activities

Financing activities provided $40 million in 2002 compared with $99 million in 2001, and required cash resources of $679 million in 2000.

Short-term liquidity is provided through funds from operations and our commercial paper program, under which we are authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. This program is supported by committed revolving credit agreements with a syndicate of banks of $750 million for a 364-day term and $250 million for a five-year term. At December 31, 2002, we had $579 million of short-term notes outstanding. The remaining short-term liquidity available of approximately $421 million under this program, together with anticipated levels of funding from operations, should be sufficient to fund our normal operating requirements.

Long-term financing is provided by our access to the debt markets, including our medium term note program. The maximum authorized principal amount of medium term notes issuable under this program is $2.5 billion and is currently available until July 2003, at which time we plan to renew the program for an additional two years. We intend to use the medium term note program to meet most of our borrowing requirements for the foreseeable future. At December 31, 2002, we had $1,050 million principal amount of medium term notes outstanding. After considering our most recent debt financing that was completed on January 28, 2003, we have approximately $950 million principal amount issuable under this program. We believe that we will be able to issue medium term notes on satisfactory terms, taking into account, among other factors, the investment grade ratings for our long-term senior, unsecured debt from major Canadian and U.S. rating agencies.

Rating Agency	Rating	
	Short-term Debt	Long-term Debt
Standard & Poor's Rating Services Inc.[1]	A-1	A
Dominion Bond Rating Service Inc.[2]	R-1 (low)	A
Moody's Investor Services Inc.[3]	Prime-1	A2

[1] On November 15, 2002, Standard & Poor's Rating Services Inc. placed Hydro One's short and long-term credit ratings on CreditWatch negative.

[2] On December 10, 2002, Dominion Bond Rating Service Inc. placed Hydro One's long-term credit rating on negative outlook.

[3] On January 24, 2003, Moody's Investor Services Inc. placed Hydro One's long-term credit ratings on review for possible upgrade.

In 2002, we issued $500 million in debt under our medium term note program and had a net increase in short-term notes of $169 million under our commercial paper program. During 2002, we repaid approximately $443 million of debt owing to OEFC. In 2001, we issued $550 million in debt under our medium term note program, had a net increase in short-term notes of $280 million under our commercial paper program and repaid $474 million of debt payable to OEFC. In 2000, the proceeds of our $1 billion inaugural bond issue, as well as other cash resources, including a net increase of $130 million in commercial paper, were used to repay $1,399 million of debt payable to OEFC.

RISK MANAGEMENT

We have an enterprise risk management program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic business objectives.

While our philosophy is that risk management is the responsibility of all employees, the Audit and Finance Committee of our Board of Directors has been mandated to review annually our company's risk tolerances, our risk profile and the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. The Hydro One Leadership Team, comprising direct reports to the President and Chief Executive Officer, provides senior management oversight of risk in the company. Our Chief Financial Officer is responsible for the ongoing monitoring and review of our risk profile and practices and for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. Each of our subsidiaries is required to complete a formal risk assessment and to develop a risk mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer and the Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing holding company and subsidiary risk tolerances, preparing risk assessments and profiles and assisting line and functional managers in fulfilling their responsibilities. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in interest rates, foreign exchange rates and commodity prices.

All of the long-term debt outstanding at December 31, 2002 is denominated in Canadian dollars and bears interest at various rates, with a weighted-average interest rate of 7.6%. We are exposed to fluctuations in interest rates as maturing debt is refinanced and periodically utilize interest rate swap agreements to mitigate elements of the interest rate risk. At the end of 2002, offsetting interest rate swap agreements with the same counter-parties were outstanding with notional principal amounts of $167 million. These agreements mature in 2011. We estimate that a 1% change in interest rates on the refinancing of long-term debt maturing in 2003 and 2004 would affect net income by approximately $2 million in 2003 and $7 million in 2004. Accordingly, we estimate that a 1% increase in interest rates in respect of our indebtedness will not have a material effect on our results of operations for 2003 or 2004. We cannot make any prediction concerning actual interest rate movements in 2003 or 2004.

Although we are not currently exposed to fluctuations in currency exchange rates, we may decide in the foreseeable future to issue foreign currency debt.

We are not exposed to commodity risk. We sold our competitive retail operations, effective April 30, 2002 and we do not engage in energy trading. With respect to our regulated transmission and distribution businesses, the OEB allows all distributors to pass commodity costs through to their customers. We do, however, experience volume risk. Rates for our transmission and distribution businesses are based on projected electricity consumption levels. A significant reduction in actual consumption levels from projections could negatively affect the rates of return of these businesses. In the event of reductions resulting from unusual circumstances, we could apply to the Minister of Energy or, subsequent to April 30, 2006, to the OEB for a rate redress.

Credit Risk

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. Our revenue is earned from a broad base of customers. As a result, we currently do not earn a significant amount of revenue from any single customer. With the commencement of Open Access, we are required to procure wholesale power on behalf of competitive retailers and embedded distribution companies for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's *Retail Settlements Code*.

Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. We monitor and minimize credit risk through various techniques including dealing with highly-rated counter-parties, limiting total exposure levels with individual counter-parties and by entering into master agreements which enable net settlement.

Risk of Recovery of Regulatory Assets

Regulatory assets primarily represent costs that have been deferred because it is probable that they will be recovered in future rates. Regulatory assets recognized as at December 31, 2002 are disclosed in Note 9 to the Consolidated Financial Statements. The rate cap created by Bill 210 limits the opportunity to recover increased costs and capital spending above current rate base levels through rates during the rate cap period, which is currently until at least April 30, 2006. A rate application can be made to the OEB before the end of this period with the written approval of the Minister of Energy. Bill 210 sets out the grounds for approval and stipulates that in deciding whether to give approval, the Minister must consider the interests of consumers with respect to prices and the reliability and quality of electricity services.

Current transmission and distribution rates provide for recovery of a significant amount of our regulatory assets. We have recognized some regulatory assets that are not incorporated in current rates. These regulatory assets primarily include the retail settlement variance accounts and the market ready costs in excess of the interim recovery of $8 million approved by the OEB. Bill 210 provides for the continuation of deferral accounts for these regulatory assets, as well as for a deferral account for the low voltage charges for direct customers and embedded local distribution companies that were approved but not implemented by December 1, 2002. In addition, the Minister of Energy has indicated, in a January 23, 2003 letter to distributors, that he will ask the OEB to complete, no later than December 31, 2003, a review of applications by distributors for recovery of the amounts that Bill 210 deems to be regulatory assets. The letter states that once the OEB completes its review and confirms the amounts to be recovered, recovery will commence no later than 2006.

We continue to believe that it is probable that our regulatory assets will be recovered through future rates, although there is more uncertainty today about full recovery than existed before Bill 210. In recognition of the increased uncertainty, we will not be reflecting the low voltage charges for direct and embedded local distribution companies in our results of operations or balance sheet for external financial reporting purposes. This revenue is estimated to be $26 million annually. We intend to seek recovery of the retail settlement variance accounts, the remaining market ready costs and the unrecorded low voltage charges, together with interest, through future rate applications.

We continually assess the likelihood of recovery of regulatory assets. If recovery through future rates was no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment was made. If a future regulatory decision was made by the OEB or the Minister of Energy to allow recovery of the low voltage charges, we would recognize a gain in the results of operations in the period that such a decision was made.

Pension Risk

We have a defined benefit registered pension plan for the majority or our employees. We have not been required to contribute to the pension plan because the actuarial valuation used to establish the contribution level indicated that the plan had a surplus. We are required to revalue our pension plan no later than December 31, 2003. As a result of the decline in financial market conditions since 2000 and the decline in long-term interest rates, we currently estimate that contributions of approximately $100 million per year could be required once our next actuarial valuation is filed. Our contributions would commence in 2004 and would continue each year until 2006. Subsequent to 2006, contributions levels would be based on the actuarial valuation required to be completed by December 31, 2006. The actual amount of the contributions that may be required in the future will depend on future investment returns, changes in benefits or actuarial assumptions. Such contributions will be attributed to labour and charged to results of operations or capitalized as part of the cost of fixed assets.

Similarly, the outsourcing agreement with Inergi includes a risk sharing agreement that could involve our company or Inergi making a payment related to a future imbalance between pension fund assets and liabilities for transferred staff covered by the Inergi Pension Plan. The risk sharing agreement will be settled based on data available on December 31, 2004 and will depend on economic factors and pension fund rates of return. If this risk sharing agreement had been settled on December 31, 2002, we would have been required to pay Inergi approximately $23 million.

We intend to seek recovery of any increased ongoing expenses related to pension costs through future rate applications for our transmission and distribution businesses. Although cash contributions could be required commencing in 2004, our rate applications may be deferred until at least May 1, 2006, unless the Minister of Energy approves the submission of a rate application to the OEB.

Environmental Risk

We manage a number of environmental risks that are primarily related to contaminated land, polychlorinated biphenyls (PCBs), spills and leaks. We have developed specific environmental management programs for these risks, including a program to systematically assess and remediate, if necessary, contaminated land and a program to identify and safely destroy PCB-contaminated equipment. We also have a program to respond to spills and to reduce the amount of insulating oil leaking from equipment.

We estimate our future expenditures associated with land assessment and remediation and PCB management. As at December 31, 2002, our estimate for future expenditures associated with land assessment and remediation was approximately $65 million. For the purpose of this estimate, we assume that remediation will be conducted, as necessary, where contamination exists off-site and exceeds Ontario Ministry of the Environment guidelines and remedial activities are required to prevent further off-site migration. We have also assumed that the Ontario Ministry of the Environment, the Federal Department of Indian Affairs and Northern Development and affected Indian bands will support our approach to assessment and remediation and that existing environmental regulations will not change. As at December 31, 2002, our estimate of future

expenditures for PCB management was approximately $153 million. This estimate assumes that existing environmental regulations regarding PCB management will not change. Our estimates are reviewed regularly and we currently expect to incur these PCB-related expenditures through to the end of 2020. As at December 31, 2002, our estimate of the net present value of the future expenditures under both programs was approximately $160 million. A regulatory asset was established at the beginning of 2001, after OEB approval, to reflect the recovery of these expenditures through our future rates.

Risks Related to Transfer of Assets on Indian Lands

We are exposed to financial risk associated with the cost to complete the transfer to our company of title to assets located on Indian lands in connection with the acquisition of our operations on April 1, 1999. Transfer of title to these assets did not occur because authorizations originally granted by the Minister of Indian Affairs and Northern Development (Canada) for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant Indian bands or bodies or, in several cases, because the authorizations had either expired or had never been properly issued. We manage these assets, which are currently owned by OEFC.

We have been negotiating with the relevant Indian bands and bodies to obtain the authorizations and consents necessary to complete the transfer of these transmission, distribution and other assets. We cannot predict the total amount that we may have to pay to obtain the required authorizations and consents. We expect to pay more than $850,000 per year, which was the amount previously paid to these Indian bands and bodies by Ontario Hydro and which is the total amount of allowed costs in the transitional rate orders. If, after taking all reasonable steps, we cannot otherwise obtain the authorizations and consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time. Alternatively, we may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial, or, in a limited number of cases, abandon a line and replace it with diesel generation facilities. In such cases, we could apply to the Minister of Energy, or subsequent to April 30, 2006, the OEB to recover these costs in future rate orders.

CRITICAL ACCOUNTING POLICIES

The preparation of our financial statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting policies involve the more significant estimates and judgements used in the preparation of our financial statements:

Regulatory Assets and Liabilities

We operate in a regulated environment. As a result, regulated assets and liabilities arise as part of the rate-making process and represent timing differences between costs being incurred or revenues being recognized versus when these amounts are reflected in rates. Regulatory assets on the balance sheet as at December 31, 2002 amounted to $570 million and principally relate to employee future benefits other than pension; estimated future expenditures required to remediate past environmental contamination (land remediation and PCB removal); market-ready costs; and the retail settlement variance accounts. We have also recorded a regulatory liability pertaining to pension costs.

These assets and liabilities can be recognized for rate-setting purposes and on financial statements only to the extent that the Minister of Energy or OEB, accepts the relevant regulatory treatment. If in a future decision, the OEB subsequently determines that the existing regulatory treatment is no longer acceptable, that regulatory asset or liability would no longer be supportable and, accordingly, would have to be charged or credited to results of operations in the period in which that determination is made.

Employee Future Benefits

We provide employee future benefits to our current and retired employees, including pension, group life insurance, health care, workers' compensation and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). We record employee future benefits other than pension costs on an accrual basis. Both of these costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management with reference to the recommendations of our actuary. The following are the significant assumptions used to determine employee future benefit costs in 2002:

	Pension	Employee Future Benefits Other than Pension
Expected rate of return on plan assets	7.25%	—
Weighted-average discount rate	6.50%	6.67%
Rate of compensation scale escalation	3.50%	3.50%
Rate of cost of living increase	2.50%	2.50%
Average remaining service life of employees (years)	12	12
Rate of increase in long-term medical costs[1]	—	4.50%
Rate of increase in dental costs[2]	—	4.50%

[1] 14.10% grading down to 4.50% after eleven years.

[2] 7.50% for four years, 4.50% thereafter.

The return on plan assets of 7.25% is based on current expectations of long-term rates of return, and reflects a pension asset mix consistent with the fund's investment policy of 60% held in listed equity securities and 40% held in corporate and government debt securities. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The weighted-average discount rate is determined by reference to the most recently available market interest rates based on AA corporate bond yields reflecting an average duration of 12.5 years.

As a result of the decline in financial market conditions, our actual rate of return on plan assets in recent years has been significantly lower than the assumed rate of return on plan assets. However, the assumed rate of return reflects our long-term expectations. We believe that this assumption is reasonable because, with the fund's balanced investment approach, the higher volatility of equity investment returns is offset by the greater stability of fixed income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. Interest rates have also declined below our assumed weighted-average discount rate used to calculate the present value of our pension liabilities. As a result of the decline in financial market conditions and the decline in long-term interest rates, we currently estimate that contributions of approximately $100 million per year could be required once our next actuarial valuation is filed, which will occur no later than December 31, 2003. A 1% reduction in the assumed rate of return would result in an increase in 2004 funding requirements of about $2 million.

The costs of employee future benefits other than pension are determined at the beginning of each year, based on an estimate of new claims costs and interest costs on the new and existing claims. Per capita claim costs have been increasing most recently as a result of rising health care cost trends, primarily for drug and other medical benefit costs. A 1% increase in the health care cost trends would result in an increase in the benefit cost of about $7 million per year.

Employee future benefits are included in labour costs and charged to results of operations or are capitalized as part of the cost of fixed assets. Changes in the assumptions will affect the amount of the employee future benefits and the current year charge to our results of operations or the amount capitalized to the cost of fixed assets.

Environmental Liabilities

We estimate our total liability for remediation of past environmental contamination and management of PCBs based on the net present value of these estimated future expenditures. We also review estimates of future environmental expenditures on an ongoing basis. These future expenditures are estimated in accordance with current environmental laws and regulations and estimates of long-term interest rates. If environmental laws and regulations or long-term interest rates change, the net present value of our environmental liabilities will be affected.

Goodwill

In assessing the recoverability of goodwill, we must make assumptions regarding estimated future cash flows and other factors to determine the fair value of the reporting unit. If these estimates or their related assumptions change in the future, we may be required to record impairment charges related to goodwill. An impairment review of goodwill was carried out during 2002 subsequent to the enactment of Bill 210. As a result of our review, we determined that no impairment of goodwill for our company existed as at December 31, 2002.

In general, in the event that our estimates and judgements incorporated in the above critical accounting policies differ from actual results, or if the Minister of Energy or the OEB, for any reason, does not set rates consistent with these policies or changes its position in respect of any of these policies, then the resulting effect on our results of operations and financial position could be material.

OUTLOOK

Our company is one of North America's largest transmission and distribution utilities. Our transmission system serves substantially the entire province of Ontario, where we are also the largest distributor. We distribute electricity to approximately 1.2 million customers located within urban, rural and remote regions of the province. Our primary focus continues to be the safe, reliable and efficient operation of our high voltage transmission and low-voltage distribution assets. These values also continue to be pursued within our growing telecommunications business.

As previously discussed, the Province announced the Electricity Action Plan on November 11, 2002 and subsequently enacted Bill 210. This has resulted in a cap on transmission and distribution rates until at least April 30, 2006. However, a rate application can be made to the OEB before this date with the written approval of the Minister of Energy. Consequently our focus continues on reducing costs, in particular within our distribution business, in order to improve our rate of return. We will build on cost reduction initiatives that are underway, such as our leaner management structure enabled through the staff reduction program. We also plan to further leverage gained and expected savings resulting from the transfer of approximately 900 employees engaged in information technology and various other business processes to Inergi, effective March 1, 2002.

In addition to our continued focus on reducing costs, we remain positioned to bring further efficiencies to the electricity sector in the province. As the largest Ontario transmitter and distributor, we have the unique skills and the geographic coverage to be a key participant in the building of an electricity market and in the establishment of a long-term supply of electricity through transmission enhancements and new interconnections. We also remain positioned to continue to participate in the further rationalization of the distribution sector in the province.

In 2002, we increased our presence in the telecommunications market through expansion of our fibre-optic network. With several new contracts and optical connections into the United States and Québec, this business has significant potential in the coming years.

Our commitment to continue to drive operational efficiency within our own company and within the sectors we serve, together with strategic investments to enhance our transmission and distribution infrastructure, are expected to provide the Ontario market place with a safe, reliable and efficient supply of electricity. This strategy should also provide our current and future debt holders with the necessary assurance for ongoing investment in our company.

RECONCILIATION TO U.S. GAAP

Net income was lower under Canadian GAAP by $3 million in 2002, and higher by $4 million in 2001 than would be the case under U.S. GAAP. Retained earnings were higher under Canadian GAAP by $393 million as at December 31, 2002, and lower by $25 million as at December 31, 2001 than would be the case under U.S. GAAP. U.S. GAAP retained earnings as at December 31, 2002 reflects a minimum pension liability. See Note 22 to the Consolidated Financial Statements for a description of the principal differences between Canadian GAAP and U.S. GAAP, as they pertain to us.

The U.S. Financial Accounting Standards Board, which is commonly referred to as "FASB", issued a series of new accounting pronouncements in 2002. See Note 22 to the Consolidated Financial Statements. Other than as described below, we do not anticipate that these FASB accounting pronouncements will have a material effect on our results of operations or financial position. Statement of Financial Accounting Standard (SFAS) 143, *Accounting for Asset Retirement Obligations*, requires the initial measurement of a liability at fair value for costs associated with disposal activities. The potential impact of adopting SFAS 143 is not yet determinable, but may be material in terms of our results of operations and financial condition under U.S. GAAP. However, under SFAS 143, regulated enterprises may recognize a regulated asset or liability for differences in timing of recognition of costs for accounting and rate-making purposes.

Management's Report

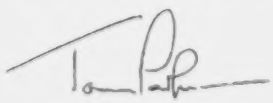
The accompanying Consolidated Financial Statements of Hydro One Inc. (Hydro One or the Company) are the responsibility of management and have been prepared in accordance with accounting principles generally accepted in Canada, and conform with accounting principles generally accepted in the United States, except as disclosed in Note 22 to the Consolidated Financial Statements. Hydro One applies accounting principles appropriate to its circumstances. The significant accounting policies followed by the Company are described in the summary of significant accounting policies contained in Note 2 to the Consolidated Financial Statements. The preparation of financial statements necessarily involves the use of estimates based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. The Consolidated Financial Statements have been properly prepared within reasonable limits of materiality and in light of information available up to February 13, 2003.

Management maintains a system of internal controls designed to provide reasonable assurance that the assets are safeguarded and that reliable financial information is available on a timely basis. The system includes formal policies and procedures and an organizational structure that provides for appropriate delegation of authority and segregation of responsibilities. An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit and Finance Committee of the Hydro One Board of Directors.

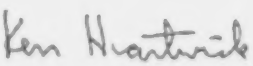
The Consolidated Financial Statements have been examined by Ernst & Young LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with generally accepted accounting principles. The Auditors' Report, which appears on page 39, outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

On behalf of Hydro One Inc.'s Management:



Tom Parkinson
President and Chief Executive Officer



K. M. Hartwick
Chief Financial Officer

To the Shareholder of Hydro One Inc.:

We have audited the Consolidated Balance Sheets of Hydro One Inc. (the Company) as at December 31, 2002 and December 31, 2001, and the Consolidated Statements of Operations, Retained Earnings and Cash Flows of the Company for each of the years in the three-year period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian and United States generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and December 31, 2001, the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2002, in accordance with Canadian generally accepted accounting principles.

The Company changed its method of accounting for goodwill and other intangible assets as described in Note 2.

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants
Toronto, Canada

February 13, 2003

Year ended December 31 (Canadian dollars in millions)	2002	2001	2000
Revenues			
Transmission *(Note 16)*	1,317	1,259	1,260
Distribution *(Note 16)*	2,695	2,158	1,703
Other	32	49	32
	4,044	3,466	2,995
Costs			
Purchased power *(Note 16)*	1,871	1,267	859
Operation, maintenance and administration *(Note 4)*	832	824	863
Depreciation and amortization *(Note 5)*	411	384	348
	3,114	2,475	2,070
Income before financing charges and provision for payments in lieu of corporate income taxes	930	991	925
Financing charges *(Notes 6 and 16)*	353	350	340
Income before provision for payments in lieu of corporate income taxes	577	641	585
Provision for payments in lieu of corporate income taxes *(Notes 7 and 16)*	233	267	207
Net income	344	374	378
Basic and fully diluted earnings per common share *(Canadian dollars) (Note 15)*	3.258	3.562	3.182

Year ended December 31 (Canadian dollars in millions)	2002	2001	2000
Retained earnings, January 1	357	241	265
Net income	344	374	378
Dividends *(Note 15)*	(192)	(258)	(402)
Distribution to shareholder *(Note 8)*	(7)	—	—
Retained earnings, December 31	502	357	241

See accompanying notes to Consolidated Financial Statements

December 31 (Canadian dollars in millions)	2002	2001
Assets		
Current assets:		
Accounts receivable (net of allowance for doubtful accounts - $16 million; 2001 - $12 million)	659	538
Materials and supplies	55	56
	714	594
Fixed assets *(Note 8)*:		
Fixed assets in service	13,790	13,335
Less: accumulated depreciation	4,859	4,581
	8,931	8,754
Construction in progress	300	310
	9,231	9,064
Other long-term assets:		
Deferred pension asset *(Note 10)*	742	847
Regulatory assets *(Note 9)*	570	558
Goodwill *(Note 11)*	133	133
Long-term accounts receivable and other assets	28	22
Deferred debt costs	7	13
	1,480	1,573
Total assets	11,425	11,231
Liabilities		
Current liabilities:		
Bank indebtedness	35	24
Accounts payable and accrued charges *(Note 10)*	589	691
Accrued interest	53	57
Short-term notes payable *(Note 12)*	579	410
Long-term debt payable within one year *(Note 12)*	651	443
	1,907	1,625
Long-term debt *(Note 12)*	3,928	4,079
Other long-term liabilities:		
Regulatory liability *(Note 9)*	742	847
Employee future benefits other than pension *(Note 10)*	540	510
Environmental liabilities *(Note 14)*	140	158
Long-term accounts payable and accrued charges	29	18
	1,451	1,533
Total liabilities	7,286	7,237
Contingencies and commitments *(Notes 13, 18 and 19)*		
Shareholder's equity *(Note 15)*		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	502	357
Total shareholder's equity	4,139	3,994
Total liabilities and shareholder's equity	11,425	11,231

See accompanying notes to Consolidated Financial Statements

On behalf of the Board of Directors:

Glen Wright
Chair

Eileen Mercier
Chair, Audit and Finance Committee

Year ended December 31 (Canadian dollars in millions)	2002	2001	2000
Operating activities			
Net income	344	574	578
Adjustments for non-cash items:			
Depreciation and amortization (net of removal costs)	384	352	324
Retail settlement variance accounts	(37)	—	—
	691	726	702
Changes in non-cash balances related to operations *(Note 17)*	(199)	188	23
Net cash from operations	492	914	725
Financing activities			
Debt for long-term financing:			
Issued	500	550	1,000
Retired	(443)	(474)	(1,399)
Debt for short-term financing	169	280	130
Deferred debt costs	6	1	(12)
Dividends paid	(192)	(258)	(398)
Net cash from (used in) financing activities	40	99	(679)
Investing activities			
Fixed assets	(570)	(566)	(446)
Acquisitions of local distribution companies	—	(475)	(23)
Proceeds from disposition *(Note 3)*	50	—	—
Other assets	(23)	28	(69)
Net cash used in investing activities	(543)	(1,013)	(538)
Net change in cash and cash equivalents	(11)	—	(492)
Cash and cash equivalents, January 1	(24)	(24)	468
Cash and cash equivalents, December 31 *(Note 17)*	(35)	(24)	(24)

See accompanying notes to Consolidated Financial Statements.

01. Incorporation and Commencement of Operations

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

02. Significant Accounting Policies

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly-owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Network Services Inc. (Hydro One Network Services), 1316664 Ontario Inc., formerly Ontario Hydro Energy Inc. (Ontario Hydro Energy), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Inc. (Hydro One Brampton), Hydro One Markets Inc., Hydro One Telecom Inc. and Hydro One Delivery Services Company Inc.

Effective January 1, 2003, Hydro One Networks and Hydro One Network Services were combined. Hydro One Network Services will be dissolved pursuant to the *Business Corporations Act* (Ontario), once all requirements are completed. In addition, the operations of the former Ontario Hydro Energy are in the process of being wound up (see Note 3).

Basis of Accounting

The Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP) and conform with accounting principles generally accepted in the United States (U.S. GAAP), except as disclosed in Note 22.

Rate-setting

Under the *Electricity Act, 1998*, as of April 1, 1999, the businesses of Ontario Hydro were reorganized into five separate corporations, including Hydro One which, through wholly owned subsidiaries, operates as the successor to Ontario Hydro's electricity transmission, distribution and energy services businesses. This restructuring was in anticipation of Ontario's wholesale and retail electricity markets becoming open to competition, which officially occurred on May 1, 2002 (Open Access). On December 9, 2002, the Province enacted the *Electricity Pricing, Conservation and Supply Act, 2002* (Bill 210), which amended the *Electricity Act, 1998* and other statutes for the purpose of implementing the Electricity Action Plan announced by the Premier of Ontario on November 11, 2002.

Rates for the transmission business for periods preceding Open Access were set by the OEB to provide for an annual rate of return of 9.88% on the amount of common equity deemed to be allocated to this business. During this period, Hydro One did not bill customers directly for transmission services. Instead, regulated transmission revenues were collected by Ontario Power Generation Inc. (OPG) and paid to the Company pursuant to a revenue allocation agreement among the successor corporations. The revenue allocation agreement ceased upon Open Access and the Independent Electricity Market Operator (IMO) now remits payments based on the uniform transmission rates approved by the OEB for all transmitters across Ontario. Based on estimated load, these rates were also set to provide for an annual rate of return of 9.88%.

Prior to Open Access, the distribution business purchased power on a fixed-price basis from OPG and charged distribution customers a bundled rate for the generation, transmission and distribution of electricity. The bundled rates originally set by the OEB for 2000 provided for an annual rate of return of 9.88% on the amount of common equity deemed to be allocated to this business. Bundled rates remained in place until Open Access.

02. Significant Accounting Policies (continued)

During 2001, the Company's wholesale cost of power was increased on two occasions. Effective June 1, 2001, the Province passed a regulation that increased to all distribution companies, including Hydro One, the wholesale cost of power supplied by OPG by 0.7 cents per kWh. The OEB approved the incorporation of this non-distribution-related increase into customers' bundled rates. The wholesale cost of power to the distribution business was further increased by 1.15 cents per kWh effective October 1, 2001 so that after such increase the Company's cost of power was consistent with the rate paid by other large distributors. On January 19, 2001, the Company applied, through Hydro One Networks, to reduce the retail portion of the distribution revenue requirement which would have been effective October 1, 2001, from approximately $742 million to $646 million to substantially mitigate the impact on Hydro One's customers of this increase in the cost of power, with this mitigation to be partially phased out over a three-year period. The Company commonly refers to this mitigation as the rate mitigation plan.

Commencing with Open Access, Hydro One purchases power from the IMO administered spot market and charges distribution customers unbundled rates, including the OEB-approved distribution rates. These distribution rates were essentially the same as the distribution rates that were incorporated into bundled rates before Open Access.

On August 30, 2002, the OEB issued a rate order establishing unbundled distribution rates; this order reflected the OEB's June 12, 2002 decision regarding the application that Hydro One Networks filed on January 19, 2001. The OEB approved an overall distribution revenue requirement (including that from retail rates, low voltage rates and miscellaneous charges) of $646 million effective October 1, 2001, $694 million effective March 1, 2002 and $742 million effective March 1, 2003. In addition, the OEB confirmed the interim approval for the recovery of approximately $8 million toward costs incurred to align our business systems and practices with the requirements of the competitive electricity market, commonly referred to as market ready costs.

Bill 210 was enacted for the purpose of implementing the Electricity Action Plan announced by the Premier of Ontario on November 11, 2002. The more significant provisions of Bill 210 for the transmission and distribution businesses are as follows:

- Energy prices for low volume and designated consumers (as defined in Bill 210) are fixed at 4.3 cents per kWh, retroactive to May 1, 2002. Most of the Company's distribution customers (who consume, in the aggregate, approximately 70% of the energy distributed) qualify for the fixed energy price. In recognition of commodity prices in excess of 4.3 cents per kWh for the period from May 1, 2002 to December 1, 2002, Bill 210 required distributors to issue a $75 refund to eligible consumers and to credit any remaining refund on future bills. The IMO has, and will continue to facilitate this price freeze through funding from Ontario Electricity Financial Corporation (OEFC), and accordingly distribution revenues and purchased power costs reported to the end of the third quarter of 2002 have been reduced by $91 million, representing an increase of $22 million in the second quarter and a decrease of $113 million in the third quarter.
- Transmission and distribution rates are capped until at least April 30, 2006. A rate application can be made to the OEB before this date with the written approval of the Minister of Energy. Any rate increases that had been approved by the OEB but not implemented by December 1, 2002 were suspended. As a result, the March 1, 2003 increase and the rate changes associated with low-voltage charges for embedded local distribution companies and direct customers cannot be implemented. The $8 million increase in distribution revenues associated with market ready costs that was approved by the OEB for the 10 months starting May 1, 2002 will remain in rates until at least April 30, 2006.
- Effective December 1, 2002, the price paid by distributors to the IMO for wholesale market charges (other than energy) is largely fixed at the same price distributors are permitted to charge their customers. For the period May 1, 2002 to December 1, 2002, differences between the rates were accumulated in retail settlement variance accounts under the provisions of Article 490 in the OEB's *Accounting Procedures Handbook* for disposition through future offsetting variances or through approved rate adjustments.

- Bill 210 provides for the establishment or continuation of deferral accounts for certain amounts until disposition is addressed by the OEB. For Hydro One, the most significant accounts include: the retail settlement variance accounts, market ready costs, and the revenue that would have been billed had the low voltage facilities charges approved for embedded local distribution companies and direct customers been implemented. Bill 210 also provides for the continuation of a deferral account for the environmental remediation costs incurred by the distribution business in 2001 and 2002. The accounting treatment for these environmental costs was reviewed with the OEB as part of the rate mitigation plan.

The enactment of Bill 210 also effectively capped rates for both Hydro One Remote Communities, through which remote communities across northern Ontario are serviced, and Hydro One Brampton, which was acquired in 2001. All other local distribution companies that were purchased have been fully integrated within Hydro One Networks, the primary operating subsidiary. As a result of the rate cap, Hydro One Remote Communities' rate of return continues to reflect a 100% debt financed capital structure and Hydro One Brampton will not be able to implement the final rate increase to be able to achieve a 9.88% return on equity as originally proposed by the OEB.

Regulatory assets primarily represent costs that have been deferred because it is probable that they will be recovered in future rates. Regulatory assets recognized at December 31, 2002 are disclosed in Note 9. The rate cap created by Bill 210 limits the opportunity to recover increased costs and capital spending above current rate base levels through rates during the rate cap period, which is currently until at least April 30, 2006. A rate application can be made to the OEB before the end of this period with the written approval of the Minister of Energy. Bill 210 sets out the grounds for approval and stipulates that in deciding whether to give approval, the Minister must consider the interests of consumers with respect to prices and the reliability and quality of electricity services.

Current transmission and distribution rates provide for recovery of a significant amount of the regulatory assets recorded as at December 31, 2002. Some regulatory assets have been recognized that are not incorporated in current rates. These regulatory assets primarily include the retail settlement variance accounts and the market ready costs in excess of the interim recovery of $8 million approved by the OEB. Bill 210 provides for the continuation of deferral accounts for these regulatory assets, as well as for a deferral account for the low voltage charges for direct customers and embedded local distribution companies that were approved but not implemented by December 1, 2002. In addition, the Minister of Energy has indicated, in a January 23, 2003 letter to distributors, that he will ask the OEB to complete, no later than December 31, 2003, a review of applications by distributors for recovery of the amounts that Bill 210 deems to be regulatory assets. The letter states that once the OEB completes its review and confirms the amounts to be recovered, recovery will commence no later than 2006.

Hydro One continues to believe that it is probable that the regulatory assets will be recovered through future rates, although there is more uncertainty today about full recovery than existed before Bill 210. In recognition of the increased uncertainty, the Company will not be reflecting the low voltage charges for direct and embedded local distribution companies in the results of operations or balance sheet for external financial reporting purposes. This revenue is estimated to be $26 million annually. Hydro One intends to seek recovery of the retail settlement variance accounts, the remaining market ready costs and the unrecorded low voltage charges, together with interest, through future rate applications.

The Company continually assesses the likelihood of recovery of regulatory assets. If recovery through future rates was no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment was made. If a future regulatory decision was made by the OEB or the Minister of Energy to allow recovery of the low voltage charges, Hydro One would recognize a gain in the results of operations in the period such a decision was made.

02. Significant Accounting Policies (continued)

The following regulatory treatments have resulted in accounting treatments differing from Canadian GAAP for enterprises operating in a non-rate-regulated environment:

- Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One recorded a regulatory asset in the original amount of $419 million to reflect this regulatory treatment;
- Hydro One provides for estimated future expenditures required to remediate past environmental contamination. Because such expenditures are recoverable through rates, the Company has recorded a regulatory asset in the original amount of $190 million. With the exception of that portion of the regulatory asset relating to certain distribution expenditures, this regulatory asset, including future interest accretion, is expected to be amortized over the period to 2020 on a basis substantially consistent with the pattern of actual expenditures. Under the Company's rate mitigation plan reviewed with the OEB, that portion of the regulatory asset related to the actual distribution expenditures incurred in 2001 and 2002 will be amortized to results of operations on a straight-line basis over the period 2005 to 2020, inclusive. The OEB has the discretion to examine and assess the extent and timing of recovery of Hydro One's environmental costs;
- Market ready costs have been deferred in accordance with the criteria set out in the OEB's *Electricity Distribution Rate Handbook, the Accounting Procedures Handbook* and in subsequent OEB guidelines. In the absence of such regulation, these costs would have been expensed when incurred under Canadian GAAP;
- Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB's *Accounting Procedures Handbook*;
- In accordance with the rate orders approved by the OEB, pension costs are recorded in the results of operations when employer contributions are paid to the pension fund rather than on an accrual basis. As a result, a regulatory liability has been recorded in an amount equal to the deferred pension asset; and
- The Company provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the OEB.

Revenue Recognition and Allocation

The rate orders issued by the OEB for the transmission business formed the basis of the revenue allocation agreement. In each of 1999, 2000, 2001 and until Open Access, transmission revenue was a fixed amount based on an annual revenue requirement of $1.2 billion. Commencing with Open Access, transmission revenues are collected through OEB-approved unbundled rates and are recognized as power is delivered to customers.

Prior to Open Access, distribution revenues attributable to the sale and delivery of electricity were based on OEB-approved bundled rates. Since Open Access, distribution revenues are based on OEB-approved unbundled distribution rates and are recognized as power is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read on a monthly basis.

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which, prior to Open Access, was collected through the revenue allocation agreement and was recognized in accordance with the terms of the agreement. Commencing with Open Access, rural rate protection amounts are received from the IMO based on a standardized customer rate approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Segment revenues for transmission, distribution and other also include revenue related to sales of services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Unbilled revenue included within accounts receivable as at December 31, 2002 amounted to $248 million ($201 - $189 million). The amount of the unbilled revenue has been presented net of the remaining amounts to be credited on future bills to reflect the fixed commodity price stipulated by Bill 210 of 4.3 cents per kWh for low volume and designated customers.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate taxes to OEFC. These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) as modified by the *Electricity Act, 1998*, and related regulations.

The Company provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Hydro One at that time.

Materials and Supplies

Materials and supplies represent spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the approved allowance for funds used during construction applicable to capital construction activities within regulated businesses, or interest applicable to capital construction activities within unregulated businesses.

Fixed assets in service consist of transmission, distribution, communication, administration and service assets and easements. Fixed assets also include future use assets such as land and capitalized development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, such as transformers, circuit breakers and switches.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Easements

Easements include statutory rights of use to transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other amounts incurred for easements and other access rights.

02. Significant Accounting Policies (continued)

Construction in Progress

Financing costs are capitalized on fixed assets under construction within regulated businesses based on the allowance for funds used during construction and within unregulated businesses using an interest capitalization rate that approximates the average cost of all long-term funds borrowed. The regulated and unregulated rates were the same for the period 2000 to 2002 (2002 – 8.1%; 2001 – 8.1%; 2000 – 8.0%).

Impairment of Fixed Assets

In the event that facts and circumstances indicate that a fixed asset or easement may be impaired, an evaluation of recoverability is performed. For purposes of such an evaluation, the estimated future undiscounted cash flows associated with the fixed asset or easement are compared to the asset's carrying amount to determine if a write-down is required.

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment and personal computers, which are depreciated on a declining balance basis.

Depreciation rates for the various classes of assets are based on their estimated service lives. The average estimated service lives and service life ranges of fixed assets are:

	Estimated service lives (years)	
	Range	Average
Transmission	12 - 100	57
Distribution	15 - 75	41
Communication	7 - 40	22
Administration and service	5 - 50	42
Easements	75	57

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining service life basis from the year the changes can first be reflected in rates.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, group life insurance, health care, workers' compensation and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). As a result, a regulatory liability is recorded in an amount equal to the deferred pension asset. The deferred pension asset arises as a result of the cumulative difference between employer contributions and pension costs. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Actuarial valuations are conducted at least every three years.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Long-term Incentive Plan

The long-term incentive compensation plan established on January 1, 2000 was cancelled in 2002. This plan measured the attainment of specific targets over three consecutive years on a rolling basis, with a new tranche of three years beginning each year. The Company recognized a liability for a three-year tranche when it was probable that the targets would be met and that a liability would be incurred, generally in the third year. The final three-year tranche was initiated on January 1, 2001 and ends on December 31, 2003.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased.

Effective January 1, 2002, Hydro One adopted the Canadian Institute of Chartered Accountants' (CICA) Handbook Section 3062, *Goodwill and Other Intangible Assets*. Under this accounting standard, goodwill is not amortized. The carrying value of goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require, with any write-down of the carrying value of goodwill being charged against the results of operations. Prior to the current standard, goodwill impairment was assessed based on estimated future undiscounted cash flows for the business to which the goodwill relates. Under CICA Handbook Section 3062, goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill.

The transitional provisions of CICA Handbook Section 3062, as they pertain to Hydro One, require the testing of goodwill at the beginning of the period in which the accounting standard is fully adopted and the disclosure of net income for the comparative period, adjusted to exclude amortization expense related to goodwill that will no longer be amortized. The Company has determined that goodwill is not impaired. All of the goodwill is attributable to the distribution business segment.

Deferred Debt Costs

Deferred debt costs include the unamortized amounts of debt discounts or premiums arising from the issuance of debt and other costs. Deferred debt costs are amortized over the period to maturity of the debt on an annuity basis.

Environmental Costs

Hydro One recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers (see Notes 9 and 14). Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Minister of Energy.

03. Sale of Competitive Retail Operations

Effective April 30, 2002, the Company sold substantially all of the assets pertaining to the competitive retail operations of the former Ontario Hydro Energy for net proceeds of approximately $50 million. The sale resulted in an initial estimated gain of $2 million before provision for payments in lieu of corporate income taxes. Under the sales agreement, a final adjustment to the purchase price occurred, reducing the gain on sale before provision for payments in lieu of corporate income taxes to $1 million.

Prior to its sale, the former Ontario Hydro Energy offered fixed price electricity contracts to residential customers in Ontario. Had Hydro One continued the competitive retail business, the former Ontario Hydro Energy would have been required to purchase electricity based on the hourly spot price in Ontario's wholesale electricity market commencing with Open Access. To hedge this risk, financial electricity swap agreements were entered into under which the former Ontario Hydro Energy was to pay the counter-party a fixed price and receive the Ontario spot price. As at December 31, 2001, the fair value of the swaps was immaterial.

Because the sale of substantially all of the assets pertaining to the competitive retail operations of the former Ontario Hydro Energy included retail energy contracts, financial electricity swap agreements and gas supply contracts, Hydro One has eliminated its exposure to the inherent commodity price and volume risks associated with the competitive retail energy business. The remaining operations are being wound up.

04. Operation, Maintenance and Administration

In September 2002, Hydro One announced that staff levels would be reduced by approximately 140 employees, primarily from head office managerial and managerial support functions. Hydro One achieved this reduction in 2002 using voluntary and involuntary measures, including those available under collective agreements for some of the affected employees. A provision of $25 million has been charged to 2002 results of operations for the estimated future expenditures of achieving this staff reduction. A total of $2 million of this amount was charged to the provision in 2002, with the remaining amount expected to be charged in 2003 and 2004.

05. Depreciation and Amortization

Year ended December 31 (Canadian dollars in millions)	2002	2001	2000
Depreciation of fixed assets in service	327	302	280
Fixed asset removal costs	27	32	24
Amortization of regulatory and other assets	57	50	44
	411	384	348

06. Financing Charges

Year ended December 31 (Canadian dollars in millions)	2002	2001	2000
Interest on short-term notes payable	15	7	2
Interest on long-term debt payable	366	371	377
Less: Interest capitalized on construction in progress	(19)	(21)	(22)
Interest capitalized on regulatory assets *(Note 9)*	(6)	(2)	—
Interest earned on investments	(3)	(5)	(17)
	353	350	340

07. Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31 (Canadian dollars in millions)	**2002**	2001	2000
Income before provision for PILs	**577**	641	585
Federal and Ontario statutory income tax rate	**38.62%**	41.74%	43.95%
Provision for PILs at statutory rate	**223**	268	257
Increase (decrease) resulting from:			
Net temporary differences:			
Capital cost allowance in excess of depreciation and amortization	**(27)**	(20)	(44)
Environmental expenditures	**(10)**	(10)	—
Interest capitalized for accounting purposes but deducted for tax purposes	**(9)**	(8)	(10)
Employee future benefits other than pension expense in excess of (lower than) cash payments	**11**	6	(4)
Charge for staff reduction program in excess of (lower than) cash payments	**9**	—	(23)
Other	**9**	14	8
Net temporary differences	**(17)**	(18)	(73)
Permanent differences:			
Large corporations tax	**17**	16	15
Other	**10**	1	8
Net permanent differences	**27**	17	23
Provision for PILs	**233**	267	207
Effective income tax rate	**40.38%**	41.65%	35.38%

Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2002, future income tax liabilities of $132 million (2001 - $105 million), based on substantively enacted income tax rates, have not been recorded.

08. Fixed Assets

December 31 (Canadian dollars in millions)	**Fixed Assets in Service**	**Accumulated Depreciation**	**Construction in Progress**	**Total**
2002				
Transmission	**7,833**	**2,619**	**180**	**5,394**
Distribution	**4,273**	**1,572**	**50**	**2,751**
Communication	**531**	**237**	**33**	**327**
Administration and service	**663**	**378**	**37**	**322**
Easements	**490**	**53**	**—**	**437**
	13,790	**4,859**	**300**	**9,231**
2001				
Transmission	7,930	2,482	132	5,580
Distribution	4,128	1,484	70	2,714
Communication	443	214	93	322
Administration and service	608	354	15	269
Easements	226	47	—	179
	13,335	4,581	310	9,064

08. Fixed Assets (continued)

Financing costs are capitalized on fixed assets under construction, including allowance for funds used during construction on regulated assets and interest on unregulated assets, and were $19 million in 2002 (2001 - $21 million; 2000 - $22 million).

In circumstances where external customers are required to make specific contributions to fund the construction and installation of specific fixed assets, Hydro One nets the customer contributions against the acquisition cost. Cumulative customer contributions in aid of construction received by Hydro One, net of amortization, except for Hydro One Brampton, were $59 million (2001 - $45 million) for transmission and $243 million (2001 - $207 million) for distribution. Hydro One's subsidiary, Hydro One Brampton, consistent with other Ontario local distribution companies, recorded contributions in aid of construction received prior to January 1, 2000 within fixed assets on a gross basis and depreciates these amounts over the remaining service lives of the assets.

On June 27, 2002, the Province passed the *Reliable Energy and Consumer Protection Act, 2002* (the Act) that amends several statutes relating to Ontario's energy sector, including the ownership and use of corridor land. Corridor land includes land in Ontario owned by Hydro One that was used or acquired for the purposes of the transmission system, including any abutting land. Under the Act, ownership of all corridor and abutting land was transferred to the Province and Hydro One was given the right to use the land to operate the transmission system. The Company retains the obligation to incur certain ongoing expenditures related to this land, including maintenance, property taxes and any future environmental remediation work that may be required by the Province. The OEB is authorized to restrict or discontinue any use of the corridor land that interferes with the transmission system.

The transfer of the corridor land was effective December 31, 2002, resulting in ownership of transmission corridors and abutting lands with a net book value of approximately $259 million being transferred to the Province in exchange for an indefinite rights of use asset. In addition, ownership of land assets with a net book value of approximately $7 million, not currently in use, was transferred to the Province and applied as a reduction of shareholder's equity.

09. Regulatory Assets and Liability

Regulatory assets and liabilities arise as a result of the rate-making process. As described in Note 2, Hydro One has recorded the following regulatory assets and liability.

December 31 (Canadian dollars in millions)	2002	2001
Regulatory assets:		
Employee future benefits other than pension	251	293
Environmental [1]	199	195
Market ready	66	64
Retail settlement variance accounts	37	—
Other	17	6
Total regulatory assets	570	558
Regulatory liability:		
Deferred pension	742	847
Total regulatory liability	742	847

[1] This asset includes $39 million (2001 - $20 million) for the environmental remediation costs incurred by the distribution business in 2001 and 2002. These costs will be amortized to the results of operations commencing 2003.

The Company's regulatory asset in respect of employee future benefits other than pension does not earn a return. This regulatory asset which amounted to $251 million as at December 31, 2002 (2001 - $293 million) has a remaining recovery period of 6 years (2001 - 7 years). In addition, Hydro One ceased adding interest to the deferral accounts for market ready costs and the retail settlement variance accounts as at December 1, 2002 for external financial reporting purposes. Hydro One intends to seek recovery of unrecorded interest amounts relating to the period after December 1, 2002 in future rate applications.

10. Employee Future Benefits

Hydro One established a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton, on January 1, 2000. As well, as of January 1, 2000, Hydro One began assuming responsibility for its proportionate share of the accrued pension benefits under the Ontario Electricity Financial Corporation Pension Plan (OEFC Pension Plan), formerly the Ontario Hydro Pension and Insurance Plan. Until that date, employees and pensioners continued to participate in the OEFC Pension Plan.

Hydro One's proportionate share of assets and liabilities under the OEFC Pension Plan was recorded under the Hydro One Pension Plan as at December 31, 2000. The OEFC Pension Plan transferred assets and liabilities to the successor plans, including the pension plan of Hydro One, in 2001.

Hydro One has not been required to contribute to the pension plan because the actuarial valuation used to establish the contribution level indicated that the plan had a surplus. The Company is required to revalue the pension plan no later than December 31, 2003 (see Note 18).

Employees of Hydro One Brampton participate in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector pension fund, which is a defined contribution plan. As Hydro One Brampton has been under a contribution holiday since August 1998, no contributions have been made to the pension fund. Effective January 1, 2003, Hydro One Brampton commenced contributing to OMERS. Contributions are estimated to be less than $1 million annually.

Prior to January 1, 2002, Hydro One self-insured its workers' compensation liability. Effective January 1, 2002, the Company's status under the *Workplace Safety & Insurance Act, 1997* changed, and as a result Hydro One is required to pay premiums to the Workplace Safety & Insurance Board. In connection with the change in employer status, the Company settled its outstanding workers' compensation liability in 2001.

10. Employee Future Benefits (continued)

	Pension		Employee Future Benefits Other than Pension	
Year ended December 31 (Canadian dollars in millions)	2002	2001	2002	2001
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	4,166	3,804	687	547
Past service costs from plan amendments	—	25	—	3
Current service cost	65	64	20	17
Interest cost	266	258	43	37
Benefits paid	(230)	(220)	(32)	(30)
Agreement with Inergi LP[1]	(127)	—	—	—
Settlement of workers' compensation liability	—	—	—	(29)
Acquisitions of local distribution companies	—	—	—	10
Net actuarial (gain) loss	(26)	237	102	132
Accrued benefit obligation, December 31	4,114	4,166	820	687
Change in plan assets				
Fair value of plan assets, January 1	4,120	4,407	—	—
Actual return on plan assets	(164)	(88)	—	—
Benefits paid	(230)	(220)	—	—
Employees' contributions	16	15	—	—
Agreement with Inergi LP[1]	(127)	—	—	—
Reciprocal transfers[2]	—	12	—	—
Administrative expenses	(8)	(6)	—	—
Fair value of plan assets, December 31	3,607	4,120	—	—
Funded status				
(Unfunded benefit obligation)	(507)	(46)	(820)	(687)
Unamortized net actuarial losses	1,230	872	244	142
Unamortized past service costs	19	21	5	8
Deferred pension asset (accrued benefit liability)	742	847	(571)	(537)
Less: current portion	—	—	31	27
Deferred pension asset (long-term liability)	742	847	(540)	(510)

[1] The reduction in the accrued benefit obligation and plan assets relates to employees transferred to Inergi LP effective March 1, 2002 (see Note 19). Subject to the approval by the Financial Services Commission of Ontario, the Hydro One Pension Plan is expected to transfer assets and liabilities to the Inergi Pension Plan in 2005.

[2] Reciprocal transfers reflect plan assets owing from, or to, the Ontario Power Generation Inc. Pension Plan, once employees have been hired from, or by, OPG and the Hydro One Pension Plan assumes, or is relieved of, the corresponding accrued benefit obligation.

	Pension			Employee Future Benefits Other than Pension		
Year ended December 31 (Canadian dollars in millions)	2002	2001	2000	2002	2001	2000
Components of net periodic benefit cost						
Current service cost, net of employee contributions	49	49	39	20	17	15
Interest cost	266	258	246	43	37	35
Expected return on plan assets	(285)	(312)	(316)	—	—	—
Amortization of net actuarial losses (gains)	73	29	—	7	—	(2)
Amortization of past service costs	2	2	—	1	1	1
Staff reduction program	—	—	—	—	—	(4)
Change in valuation allowance[1]	—	(421)	31	—	—	—
Net periodic benefit cost	105[2]	(395)[2]	—	71	55	45
Capitalized as part of the cost of fixed assets	—	—	—	28	22	21
Charged to results of operations	—	—	—	43	33	24
Effect of 1% increase in health care cost trends on:						
Accrued benefit obligation, December 31	—	—	—	104	72	54
Net periodic benefit cost	—	—	—	7	5	5
Effect of 1% decrease in health care cost trends on:						
Accrued benefit obligation, December 31	—	—	—	(87)	(58)	(44)
Net periodic benefit cost	—	—	—	(5)	(4)	(4)
Significant assumptions						
Expected rate of return on plan assets	7.25%	7.50%	7.75%	—	—	—
Weighted-average discount rate	6.50%	6.50%	6.75%	6.67%	6.66%	6.88%
Rate of compensation scale escalation	3.50%	3.50%	3.25%	3.50%	3.50%	3.25%
Rate of cost of living increase	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Average remaining service life of employees (years)	12	12	14	12	12	14
Rate of increase in long-term medical costs[3]	—	—	—	4.50%	4.50%	4.50%
Rate of increase in dental costs[4]	—	—	—	4.50%	3.50%	3.50%

[1] The valuation allowance reduces the deferred pension asset to the maximum future benefit Hydro One expects to realize from the plan surplus. In 2001, Hydro One reversed the valuation allowance that was previously applied against the deferred pension asset.

[2] The regulatory liability was adjusted by a corresponding amount, and as a result there was no impact on operations.

[3] 11.10% grading down to 4.50% after eleven years (2001 – 10.00% grading down to 4.50% after eight years, 2000 – 9.00% grading down to 4.50% after five years).

[4] 7.30% for four years, 4.50% thereafter (2001 – 5.00% for five years, 3.50% thereafter, 2000 – 3.5% per annum).

11. Acquisitions of Local Distribution Companies

During 2002, Hydro One did not make any significant acquisitions. However, during 2001, Hydro One acquired the outstanding shares or assets of 71 local distribution companies for net cash consideration of approximately $475 million. Net identifiable assets acquired amounted to approximately $347 million, representing assets of $416 million and liabilities of $69 million. Based on the allocation of the purchase price, the transactions resulted in goodwill of $128 million in 2001. Combined with goodwill from 2000 of $6 million, the total goodwill under the acquisition program, before amortization, was $134 million. These acquisitions were accounted for by the purchase method with the acquired companies' results of operations being included in the Consolidated Statement of Operations from the dates of acquisition.

Goodwill amortized during 2001 was $1 million. Goodwill recognized after June 30, 2001, which is not subject to amortization, was $93 million.

12. Debt

December 31 (Canadian dollars in millions)	2002	2001
Short-term notes payable	579	410
Long-term debt:		
Notes payable to OEFC	2,529	2,972
6.94% debentures due 2005	200	200
7.15% debentures due 2010	400	400
6.40% notes due 2011	250	250
5.77% notes due 2012	300	—
7.35% debentures due 2030	400	400
6.95% notes due 2032	500	500
	4,579	4,522
Less: long-term debt payable within one year	651	443
Long-term debt	3,928	4,079

Short-term debt represents promissory notes issued pursuant to the Company's commercial paper program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days and with a weighted-average interest rate of 2.9% (2001 - 2.16%).

Notes payable to OEFC are denominated in Canadian dollars with various maturity dates between 2003 and 2007, and with a weighted-average interest rate of 8.2% (2001 - 8.6%) (See Note 21).

The Company also issues notes for long-term financing under the medium term note program. Hydro One is authorized to issue notes in aggregate principal amount of $2.5 billion under the program (see Note 21).

The long-term debt is subject to covenants that, among other things, limit permissible debt as a percentage of total capitalization, limit ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2002, the Company was in compliance with these covenants.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding on Notes and Debentures *(Canadian dollars in millions)*	Principal Outstanding on Notes Payable to OEFC *(Canadian dollars in millions)*	Weighted Average Interest Rate *(Percent)*
1 year	—	651	7.2
2 years	—	682	6.8
3 years	200	307	7.7
4 years	—	589	10.3
5 years	—	300	9.2
	200	2,529	8.1
6 – 10 years	950	—	6.5
Over 10 years	900	—	7.1
	2,050	2,529	7.6

Hydro One has committed and unused revolving credit agreements with a syndicate of banks in the amount of $750 million which matures in 2003 and $250 million which matures in 2005. If used, interest on the lines of credit would apply based on Canadian benchmark rates. These credit agreements support the Company's commercial paper program.

13. Fair Value of Financial Instruments and Risk Management

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of long-term debt, based on year-end quoted market prices for the same or similar debt of the same remaining maturities, is provided in the following table:

December 31 (Canadian dollars in millions)	2002		2001	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt	**4,579**	**4,925**	4,522	4,956

Hydro One may enter into forward pay fixed interest rate swap agreements to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. When the hedged borrowing occurs, Hydro One terminates the hedge either by terminating the interest rate swap or by entering into an offsetting swap agreement. As at December 31, 2002, offsetting interest rate swap agreements were outstanding with the same counter-party having notional principal amounts of $167 million (2001 - $167 million) and a fair value of $nil (2001 - $nil). The swap agreements mature in 2011.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2002, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any single customer. As at December 31, 2002, there were no significant balances of accounts receivable due from any single customer.

The Company will continue to use derivative instruments to manage interest rate risk. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. Hydro One monitors and minimizes credit risk through various techniques including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties and entering into master agreements which enable net settlement.

14. Environmental Liabilities

December 31 (Canadian dollars in millions)	**2002**	2001
Environmental liabilities	**160**	174
Less: current portion	**(20)**	(16)
	140	158

Hydro One changed its accounting policy for environmental obligations on January 1, 2001 and recognized a liability for the present value of the estimated future expenditures to assess and remediate contaminated lands and to manage PCB contamination. As at January 1, 2001, the total estimated future expenditures, based on existing regulations, amounted to $95 million for land assessment and remediation and $170 million for PCB management. These amounts, expected to be incurred over the period 2001 to 2020 inclusive, were discounted using a 6.25% interest rate, resulting in an opening January 1, 2001 environmental obligation of $190 million.

During 2002, expenditures of $23 million were charged to this provision (2001 - $26 million) and $9 million (2001 $10 million) of interest was added, resulting in a December 31, 2002 balance of $160 million (December 31, 2001 - $174 million). Hydro One's estimate of future environmental expenditures did not change during 2002 or 2001.

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2002 and in total thereafter are as follows: 2003 - $25 million; 2004 - $21 million; 2005 - $19 million; 2006 - $18 million; 2007 - $17 million; and thereafter - $118 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. Hydro One continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

15. Share Capital

Common and Preferred Shares

On March 31, 2000, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares with a redemption value of $25.00 per share, and 99,990 common shares, bringing the total number of outstanding common shares to 100,000. The Company is authorized to issue an unlimited number of preferred and common shares.

The preferred shares are entitled to an annual cumulative dividend of $18 million, which is payable on a quarterly basis. The preferred shares are redeemable at the option of the Province at a price of $25.00 per share, representing the stated value, plus any accrued and unpaid dividends if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

Dividends

Common dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2002, preferred dividends in the amount of $18 million (2001 - $18 million) and common dividends in the amount of $174 million (2001 - $240 million) were declared.

Earnings per Share

Earnings per share is calculated as net income during the year, after cumulative preferred dividends, divided by the weighted-average number of common shares outstanding during the year. Earnings per share for 2000 reflect the issuance of common shares on March 31, 2000.

16. Related Party Transactions

The Province, OEFC, OPG and the IMO are related parties of Hydro One. Transactions between these parties and Hydro One were as follows:

Prior to Open Access, Hydro One received revenue for transmission services consistent with the revenue allocation agreement (see Note 2). Commencing with Open Access, Hydro One receives such revenue from customer revenue collected by the IMO. Transmission revenue for 2002 includes $1,269 million (2001 - $1,213 million; 2000 - $1,182 million) related to these services.

Prior to Open Access, Hydro One received a portion of its distribution revenue consistent with the revenue allocation agreement (see Note 2). Under this agreement, distribution revenue for 2002 includes $10 million related to these services (2001 - $52 million; 2000 - $59 million).

Prior to Open Access, Hydro One also received revenue related to the supply of electricity to 19 remote northern communities consistent with the revenue allocation agreement (see Note 2). Commencing with Open Access, Hydro One receives such revenue from customer revenue collected by the IMO. Distribution revenue for the year ended December 31, 2002 includes $21 million (2001 - $21 million; 2000 - $17 million) related to these services.

Hydro One receives amounts for rural rate protection from customer revenue collected by the IMO (see Note 2). Distribution revenue for 2002 includes $127 million (2001 - $127 million; 2000 - $127 million) related to this program, of which $5 million (2001 – $5 million; 2000 - $7 million) was paid to local distribution companies in respect of annexation agreements.

Hydro One purchased power from the IMO administered spot market (from OPG prior to Open Access) in the amount of $1,870 million in 2002 (2001 - $1,265 million; 2000 - $857 million).

Hydro One has several service level agreements with the other successor corporations, primarily OPG. These services include field and engineering, logistics, corporate, telecommunications and information technology services. Revenues related to the provision of services to the other successor corporations and operation, maintenance and administration costs related to the purchase of services from the other successor corporations are summarized in the following table:

Year ended December 31 (Canadian dollars in millions)	**2002**	2001	2000
Revenues			
Transmission	**12**	16	61
Distribution	**2**	7	3
	14	23	64
Operation, maintenance and administration			
Transmission	**—**	3	15
Distribution	**—**	1	3
	—	4	18

As at December 31, 2002, long-term debt in the amount of $2,529 million ($2001 - $2,972 million) was due to OEFC. Financing charges for 2002 include interest expense on this debt in the amount of $240 million ($2001 - $288 million; 2000 - $330 million).

The provision for payments in lieu of corporate income taxes was paid or payable to OEFC and dividends were paid or payable to the Province (see Note 2).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in millions)	**2002**	2001
Accounts receivable	**118**	119
Accounts payable and accrued charges	**(156)**	(256)

Included in accounts payable and accrued charges are amounts owing to the IMO (OPG in 2001) in respect of power purchases of $143 million ($2001 - $188 million).

17. Consolidated Statements of Cash Flows

For the purposes of the consolidated statements of cash flows, "cash and cash equivalents" refers to the balance sheet item "bank indebtedness."

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	**2002**	2001	2000
Accounts receivable (increase) decrease	**(121)**	(149)	25
Materials and supplies decrease	**1**	9	16
Accounts payable and accrued charges (decrease) increase	**(102)**	334	(46)
Accrued interest (decrease)	**(4)**	(7)	(8)
Long-term accounts payable and accrued charges increase	**11**	5	6
Employee future benefits other than pension increase	**30**	1	13
Other	**(14)**	(5)	17
	(199)	188	23
Supplementary information:			
Interest paid	**379**	383	384
Payments in lieu of corporate income taxes	**294**	241	213

18. Contingencies

Legal Proceedings

As a result of Hydro One's acquisition of certain transmission, distribution and energy services assets, liabilities, rights and obligations of Ontario Hydro, Hydro One has succeeded Ontario Hydro as a party in a number of legal proceedings. In 1995, Torcom Communications Inc. (Torcom) named Ontario Hydro as one of several defendants in a suit seeking damages of $150 million, as well as specific performance of certain agreements and interim injunctive relief. Torcom had sought to purchase certain telecommunication devices belonging to a bankrupt company from the court-appointed receiver. The devices had been installed on Ontario Hydro property under licence to the original owner. Torcom claims that it reached an agreement with Ontario Hydro for the continued placement of the devices on Ontario Hydro property. Torcom alleges Ontario Hydro breached this contract and interfered with its efforts to purchase the devices from the receiver. There has been little activity on the case since 1995, when Ontario Hydro served a demand to particularize the allegations against it. Ontario Hydro did not receive a reply to its demand for particulars and has not yet served a statement of defence. Hydro One believes that there are strong defences to the plaintiff's claims against Ontario Hydro and that it is unlikely that the outcome of the litigation will have a material adverse effect on its business, results of operations, financial position or prospects.

Hydro One is one of many defendants in a suit in the Superior Court of Justice commenced on October 18, 1995, asserting aboriginal title to certain land within the City of Sarnia. The plaintiff, The Chippewas of Sarnia Band, alleges that the land was not properly surrendered before a Crown Patent was issued in 1853, and therefore subsequent owners who took possession under the Crown Patent do not possess valid title. Hydro One maintains transmission line facilities on portions of the disputed land. Hydro One cannot estimate the costs that might result from an adverse decision. On April 30, 1999, summary judgment was granted, dismissing the action against Ontario Hydro and certain defendants. On May 27, 1999, the plaintiff appealed the summary judgment order to the Court of Appeal for Ontario. Further, several defendants have also appealed the summary judgment order and others, including Hydro One, have filed cross-appeals. The appeals were argued in June 2000. The Court of Appeal decision rendered December 21, 2000 dismissed the plaintiffs' appeal and granted the appeals of the other parties. The plaintiff filed a motion for leave to appeal to the Supreme Court of Canada. On November 8, 2001, the Supreme Court of Canada dismissed the leave to appeal application with costs, thereby affirming the Court of Appeal decision. On December 18, 2001, the plaintiff brought a motion for reconsideration of the leave to appeal decision and seeks a reversal of the denial of the leave application or an order for an oral hearing of the leave to appeal application. Such orders are rare and are made only in exceptional circumstances. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on its business, results of operations, financial position or prospects.

On March 29, 1999, the Whitesand First Nation Band commenced an action in the Ontario Court (General Division), naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG and the Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The reason for the second claim is the procedural defence of the Province that proper notice of the first claim was not given under the *Proceedings Against the Crown Act* (Ontario). These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The Whitesand Band alleges that since at least the first half of the twentieth century, Ontario Hydro has erected dams, generating stations and other facilities within or affecting the band's traditional lands and that those facilities have caused damage to band members and the lands, including substantial flooding and erosion. The Whitesand Band also claims treaty rights to a share of the profits arising from the activities of these Ontario Hydro facilities, an entitlement to increases in annuity payments established by treaty, and compensation for costs incurred in the course of prior negotiations of band grievances with Ontario Hydro. The Whitesand Band asserts multiple causes of action, including trespass, breach of fiduciary duty, nuisance and negligence. To date, Hydro One has not filed a defence. The Company has requested particulars of the claims, as have the other defendants. Following receipt, Hydro One will be filing a defence. The claims relating to activities of Ontario Hydro (i.e., flooding) are the matters for which OPG would have responsibility pursuant to Transfer Orders under the Electricity Act, 1998. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on its business, results of operations, financial position or prospects.

Transfer of Assets

On April 1, 1999, in connection with the acquisition of its operations, Hydro One acquired and assumed the assets, liabilities, rights and obligations of Ontario Hydro's electricity transmission, distribution and energy services businesses, except for certain transmission, distribution and other assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Transfer of title to these assets did not occur because authorizations originally granted by the Minister of Indian Affairs and Northern Development (Canada) for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant Indian bands or bodies or, in several cases, because the authorizations had either expired or had never been properly issued. Hydro One manages these assets, which are currently owned by OEFC.

Hydro One has commenced negotiations with the relevant Indian bands and bodies to obtain the authorizations and consents necessary to complete the transfer of these transmission, distribution and other assets. Hydro One cannot predict the aggregate amount that it may have to pay to obtain the required authorizations and consents. Hydro One expects to pay more than $850,000 per year, which was the amount previously paid to these Indian bands and bodies by Ontario Hydro and which was the total amount of allowed costs in the transitional rate orders. If, after taking all reasonable steps, Hydro One cannot otherwise obtain the authorizations and consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time. Alternatively, Hydro One may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial, or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. In such cases, Hydro One would apply to the Minister of Energy, or subsequent to April 30, 2006, the OEB to recover these costs in future rate orders.

Pension Risk

Hydro One has a defined benefit registered pension plan for the majority of employees. The Company has not been required to contribute to the pension plan because the actuarial valuation used to establish the contribution level indicated that the plan had a surplus. The Company is required to revalue the pension plan no later than December 31, 2003. As a result of the decline in financial market conditions since 2000 and the decline in long-term interest rates, Hydro One currently estimates that contributions of approximately $100 million per year could be required once the next actuarial valuation is filed. The contributions would commence in 2004 and would continue each year until 2006. Subsequent to 2006, contribution levels would be based on the actuarial valuation required to be completed by December 31, 2006. The actual amount of the contributions that may be required in the future will depend on future investment returns, changes in benefits or actuarial assumptions. Such contributions will be attributed to labour and charged to results of operations or capitalized as part of the cost of fixed assets.

Similarly, the outsourcing agreement with Inergi LP (Inergi) includes a risk sharing agreement that could involve either Hydro One or Inergi making a payment related to a future imbalance between pension fund assets and liabilities for transferred staff covered by the Inergi Pension Plan. The risk sharing agreement will be settled based on data available on December 31, 2004 and will depend on economic factors and pension fund rates of return. If this risk sharing agreement had been settled on December 31, 2002, Hydro One would have been required to pay Inergi approximately $23 million. (See Note 19).

The Company intends to seek recovery of any increased ongoing expenses related to pension costs through future rate applications for the transmission and distribution businesses. Although cash contributions could be required commencing in 2004, rate applications may be deferred until at least May 1, 2006, unless the Minister of Energy approves the submission of a rate application to the OEB.

19. Commitments

Agreement with Inergi

Effective March 1, 2002, Cap Gemini Ernst & Young Canada began providing services to Hydro One through a new entity, Inergi. As a result of this initiative, Hydro One will receive from Inergi a range of services including information technology, customer care, supply chain and certain human resources and finance services for a ten-year period. The initial service level price ranges between $90 million and $130 million per year, subject to external benchmarking every three years to ensure Hydro One is receiving a defined competitive and continuously improved price. In connection with this agreement, on March 1, 2002 the Company transferred approximately 900 employees to Inergi.

The annual commitments under the agreement in each of the five years subsequent to December 31, 2002, and in total thereafter are as follows: 2003 - $120 million; 2004 - $112 million; 2005 - $104 million; 2006 - $100 million; 2007 - $99 million; and thereafter - $384 million.

Prudential Support

Purchasers of electricity in Ontario, through the IMO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IMO could draw on these guarantees if Hydro One Networks or Hydro One Brampton fails to make a payment required by a default notice issued by the IMO. The maximum potential payment is the face value of the bank letters of credit plus the nominal amount of the parental guarantee. As at December 31, 2002, the Company provided prudential support, using a combination of bank letters of credit of $50 million (2001 - $50 million) and parental guarantees of $275 million (2001 - $275 million).

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The trustee is required to draw upon the letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2002, Hydro One had bank letters of credit of $97 million (2001 - $108 million) outstanding relating to retirement compensation arrangements.

Operating Leases

The future minimum lease payments under operating leases for each of the five years subsequent to December 31, 2002 and in total thereafter are as follows: 2003 - $10 million; 2004 - $8 million; 2005 - $2 million; 2006 - $1 million; 2007 - $1 million; and thereafter – $3 million.

20. Segment Reporting

Hydro One has three reportable segments:

- The transmission business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The distribution business, which comprises the core business of delivering and selling electricity to customers; and
- The "other" segment, which primarily consists of energy services, telecommunications and head office. Substantially all of the assets pertaining to the competitive retail operations of the energy services business have been sold and the remaining operations will be wound up (See Note 3).

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2). Segment information on the above basis is as follows:

Year ended December 31 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2002				
Segment profit				
Revenues	1,317	2,695	32	4,044
Purchased power	—	1,870	1	1,871
Operation, maintenance and administration	374	383	75	832
Depreciation and amortization	213	190	8	411
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	730	252	(52)	930
Financing charges				353
Income before provision for payments in lieu of corporate income taxes				577
Capital expenditures	260	286	24	570
2001				
Segment profit				
Revenues	1,259	2,158	49	3,466
Purchased power	—	1,265	2	1,267
Operation, maintenance and administration	354	591	79	824
Depreciation and amortization	219	163	2	384
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	686	339	(34)	991
Financing charges				350
Income before provision for payments in lieu of corporate income taxes				641
Capital expenditures	274	247	45	566
2000				
Segment profit				
Revenues	1,260	1,703	32	2,995
Purchased power	—	857	2	859
Operation, maintenance and administration	433	388	42	863
Depreciation and amortization	198	143	7	348
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	629	315	(19)	925
Financing charges				340
Income before provision for payments in lieu of corporate income taxes				585
Capital expenditures	280	152	14	446

[1] Capital expenditures exclude $468 million in 2001 and $23 million in 2000 associated with acquisitions of local distribution companies.

December 31 (Canadian dollars in millions)	2002	2001
Total assets		
Transmission	6,635	6,693
Distribution	4,700	4,416
Other	90	122
	11,425	11,231

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

21. Subsequent Events

OEFC Debt

On January 24, 2003, Hydro One announced that OEFC intends to sell some or all its Hydro One debt in the Canadian public debt markets, commencing early in 2003. The notes payable to OEFC mature between 2003 and 2007, with a weighted-average term to maturity of approximately two years. In order to facilitate the sale, Hydro One agreed in principle with OEFC to restructure some or all of the Hydro One debt held by OEFC.

On February 13, 2003, the Board of Directors approved the exchange of up to $1.9 billion of existing debt with a weighted-average interest rate of approximately 8% for up to approximately $2.15 billion of debt with a weighted-average interest rate of approximately 4%. This debt restructuring will result in lower cash interest payments for Hydro One from 2003 through 2007 and a corresponding increase in the principal amount of the debt payable at maturity. The maturity dates will remain essentially unchanged.

For accounting purposes, the exchange will be a renegotiation of debt and no gain or loss will be recognized. The net carrying amount of the new notes (principal less unamortized discount) on the balance sheet will equal the carrying amount of the existing notes.

Debt Issue

On January 28, 2003, Hydro One issued notes with a principal amount of $500 million under the Company's medium term note program. The notes were issued in two tranches: a re-opening of Series 3 for $300 million at a coupon rate of 5.77% due November 15, 2012 and Series 4 for $200 million at a coupon rate of 6.35% due January 31, 2034. The total outstanding for Series 3 is now $600 million.

22. Reconciliation to U.S. GAAP

The Consolidated Financial Statements of Hydro One have been prepared in accordance with Canadian GAAP, which conforms in most respects to U.S. GAAP. Under both Canadian GAAP and U.S. GAAP, certain of the Company's accounting policies differ from those that would be followed by enterprises operating in a non-rate-regulated environment.

The material differences between Canadian GAAP, as used in the preparation of these Consolidated Financial Statements, and U.S. GAAP are summarized below.

Consolidated Statements of Operations

Year ended December 31 (Canadian dollars in millions)	2002	2001	2000
Net income	**344**	374	378
Adjustments increase (decrease):			
Employee future benefits other than pension (a)	**8**	(2)	(6)
Staff reduction charges (c)	**—**	—	(60)
Corporate write-offs (d)	**(5)**	(2)	(2)
Net income (U.S. GAAP)	**347**	370	310
Other comprehensive income (b)	**(421)**	—	—
Comprehensive income (U.S. GAAP)	**(74)**	370	310
Retained earnings, opening (U.S. GAAP)	**382**	270	362
Dividends	**(192)**	(258)	(402)
Distribution to shareholder	**(7)**	—	—
Retained earnings, December 31 (U.S. GAAP)	**109**	382	270

Consolidated Balance Sheets

December 31 (Canadian dollars in millions)	2002	2001
Assets: increase (decrease)		
Fixed assets in service (a),(d)	**8**	19
Deferred pension asset (b)	**(321)**	(421)
Regulatory assets - future tax (e)	**—**	118
Future tax asset (b),(e)	**163**	—
Other assets (b)	**19**	—
Liabilities: (increase) decrease		
Accounts payable and accrued charges (d)	**8**	8
Employee future benefits other than pension (a)	**12**	(2)
Minimum pension liability (b)	**(119)**	—
Regulatory liability - pension (b)	**—**	421
Regulatory liability - future tax (b),(e)	**(28)**	—
Future tax liability (e)	**(135)**	(118)
	(393)	25

(a) Employee Future Benefits Other than Pension

Under U.S. GAAP, actuarial gains or losses for post-employment benefits are immediately recognized in results of operations. Under Canadian GAAP, such amounts can be deferred and amortized over the average remaining service period of active employees. Under U.S. GAAP, liabilities for other post-employment benefit costs would have been $14 million lower in 2002 (2001 - $4 million higher; 2000 - $11 million higher) due to the immediate recognition of the actuarial gain resulting from a change in the settlement rate at December 31. Of this, $8 million would have been credited to the results of operations (2001 - $2 million charged; 2000 - $6 million charged) and $6 million would have been credited to the cost of fixed assets (2001 - $2 million capitalized; 2000 - $5 million capitalized).

(b) Other Comprehensive Income

Under U.S. GAAP, if an entity's accrued pension benefit obligation, without considering future salary escalation, exceeds the fair value of pension plan assets, a minimum pension liability is to be recognized. The amount of the adjustment to record the minimum pension liability is equal to the unfunded accrued pension benefit obligation, without considering future salary escalation, plus any amounts reported as a deferred pension asset. The adjustment amount is to be recognized as an intangible asset to the extent of unrecognized past service costs. Any excess of the adjustment amount over unrecognized past service costs is reported as a separate component (reduction) of equity. For financial statement presentation, the reduction to shareholder's equity is an item of other comprehensive income (OCI). The associated tax benefit that results from considering the reduction to shareholder's equity as a temporary difference, determined on the basis of enacted income tax rates, is reflected as an adjustment to the balance sheet (see Note 22 (e)).

Under U.S. GAAP, the amount of the reported deferred pension asset would be different than that for Canadian GAAP since valuation allowances are not permissible. In 2001, Hydro One's deferred pension asset increased as a result of the reversal of previously applied valuation allowances (see Note 10). Under U.S. GAAP, the amount of the reported deferred pension asset could not be similarly increased, and as a result, would have been $321 million as at December 31, 2002 (2001 - $426 million). For purposes of the U.S. GAAP reconciliation, the adjustment amount to record the minimum pension liability is combined with the deferred pension asset.

22. Reconciliation to U.S. GAAP (continued)

(c) Staff Reduction Charges

Under Canadian GAAP, prior to January 1, 2000, costs relating to staff reduction programs were recognized at the time management approved such reductions and the costs could be reasonably estimated. Under U.S. GAAP, the cost of staff reduction programs cannot be recognized unless the program meets specific additional criteria and, for voluntary retirement programs, if the employees actually accept an offer of early retirement. During 2000, Hydro One reversed a 1999 provision for voluntary staff reduction costs in the amount of $5 million as a credit to the results of operations. Under U.S. GAAP, the original 1999 provision would not have been recorded. Instead, a provision for $55 million would have been recorded in 2000 as employees actually accepted the early retirement offer. Therefore, U.S. GAAP income would have been lower in 2000 by $60 million due to a combination of the $55 million staff reduction provision and the absence of the $5 million credit resulting from the 2000 reversal of a portion of the provision recognized under Canadian GAAP in 1999. A U.S. GAAP reconciling item is not required for the 2002 staff reduction charge because Canadian GAAP now conforms to U.S. GAAP.

(d) Corporate Write-offs

In 1997, Ontario Hydro recorded a $33 million expense related to the future disposal of certain field operation centres, consisting of a $25 million write-down of fixed assets and an $8 million provision for non-discretionary post-occupancy costs. Under U.S. GAAP, the fixed assets would have remained on the balance sheet as assets held for future use and would have continued to be depreciated at $2 million per year. In the absence of the 1999 write-down, the Company's 2002 U.S. GAAP depreciation expense would also have been $3 million greater due to losses from related asset sales. In addition, the provision for non-discretionary post-occupancy costs would not have been recorded.

(e) Future Income Taxes

For a rate-regulated enterprise, U.S. GAAP requires the reporting and display of future income tax liabilities and assets on the balance sheet. To the extent that future income taxes are expected to be included in the approved rates charged to customers in the future, the Company would record a regulatory asset. The amount of regulatory asset and the future tax liability reported for U.S. GAAP for 2002, determined on the basis of enacted income tax rates, would be $135 million (2001 - $118 million). However, in 2002, the tax benefit associated with recording a minimum pension liability would be $163 million, such that for U.S. GAAP purposes, the Company would also record a future tax asset, and subsequently a net regulatory liability for $28 million (see Note 22 (b)).

(f) Derivative Instruments and Hedging Activities

The Company's interest rate swap contracts (see Note 13) are derivative financial instruments as defined in Statement of Financial Accounting Standard (SFAS) 133, *Accounting for Derivative Instruments and Hedging Activities*. The interest rate swaps would be accounted for under SFAS 133 as cash flow hedges of forecasted borrowings. To the extent the swap contracts are effective hedges, changes in fair value would be reported in OCI and transferred to results of operations when interest on the hedged borrowings is recognized. In addition, premiums or discounts recorded when Hydro One terminates hedges related to future borrowing requirements would be reported in OCI and transferred to results of operations when interest on the hedged borrowings is recognized. The fair value of the interest rate swaps as at December 31, 2002 was $nil (December 31, 2001 - $nil) and the premium received in 2001 of $2 million was immaterial and, therefore, there would be no material effect on results of operations or financial position as a result of applying SFAS 133.

(g) Earnings per Share

Under U.S. GAAP, the following supplemental disclosure with respect to earnings per share is required:

(Canadian dollars in millions, except per share data)	Income *(Numerator)*	Shares *(Denominator)*	Per-Share Amount
2002			
Income before extraordinary items and accounting changes	344		
Less: Preferred share dividends	18		
Basic and fully diluted earnings per common share[1]			
Income available to common shareholder	326	100,000	3.258
2001			
Income before extraordinary items and accounting changes	574		
Less: Preferred share dividends	18		
Basic and fully diluted earnings per common share[1]			
Income available to common shareholder	556	100,000	5.562
2000			
Income before extraordinary items and accounting changes[2]	252		
Less: Preferred share dividends	13		
Basic and fully diluted earnings per common share[1]			
Income available to common shareholder	239	75,000	3.182

[1] For each of the years in the three-year period ended December 31, 2002, there were no issued or outstanding dilutive securities.
[2] Represents the results of operations for the nine months ended December 31, 2000.

(h) Statements of Cash Flows

Under U.S. GAAP, bank indebtedness is not included in deriving cash and cash equivalents for purposes of the statements of cash flows. Bank indebtedness is classified as a financing activity.

(i) Future Accounting Pronouncements

On June 30, 2001, the Financial Accounting Standards Board (FASB) approved SFAS 143, *Accounting for Asset Retirement Obligations*, for obligations associated with the retirement of long-lived assets. SFAS 143 requires a liability to be recognized in the financial statements for retirement obligations meeting specific criteria. Measurement of the initial obligation is to approximate fair value with an equivalent amount recorded as an increase in the value of the capitalized asset. The asset will be depreciated in accordance with normal depreciation policy and the liability will be increased for interest accretion, with a charge to the statement of operations, until the obligation is settled. Regulated enterprises may recognize a regulated asset or liability for differences in timing of recognition of costs for accounting and rate-making purposes. SFAS 143 is effective for fiscal years beginning after June 15, 2002. The potential impact of adopting SFAS 143 is not yet determinable, but may be material.

On June 28, 2002, the FASB approved SFAS 146, *Accounting for Exit or Disposal Activities*. SFAS 146 addresses the recognition, measurement, and reporting of costs that are associated with exit and disposal activities, including restructuring activities. SFAS 146 requires that the initial measurement of a liability for costs associated with disposal activities should be recorded at fair value. In periods subsequent to initial measurement, changes to the liability should be measured using the credit-adjusted risk-free rate that was used to measure the liability initially. The cumulative effect of a change resulting from a revision to either the timing or the amount of estimated cash flows should be recognized as an adjustment to the liability in the period of the change and reported in the same line item(s) in the income statement used when the related costs were recognized initially. Changes due to the passage of time should be recognized as an increase in the carrying amount of the liability and as an expense (for example, accretion expense). The provisions of the statement will be effective for disposal activities initiated after December 31, 2002, with early application encouraged. The impact of adopting SFAS 146 is not expected to be material.

23. Comparative Figures

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2002 Consolidated Financial Statements.

Year ended December 31 (Canadian dollars in millions)	**2002**	2001	2000	1999	1998
Statement of operations data					
Revenues	**4,044**	5,466	2,995	5,125	5,048
Costs					
Purchased power	**1,871**	1,267	859	939	1,165
Operation, maintenance and administration[2]	**832**	824	863	865	725
Depreciation and amortization	**411**	384	348	342	300
Transitional cost adjustment[3]	**—**	—	—	55	—
Provincial debt guarantee fee[4]	**—**	—	—	8	31
Deferred pension asset[5]	**—**	—	—	—	(204)
	3,114	2,475	2,070	2,207	2,015
Other income					
Gain on sale of investment[6]	**—**	—	—	32	—
Income before financing charges and provision for payments in lieu of corporate income taxes	**930**	991	925	950	1,033
Financing charges	**353**	350	340	381	559
Income before provision for payments in lieu of corporate income taxes	**577**	641	585	569	474
Provision for payments in lieu of corporate income taxes[7]	**233**	267	207	194	—
Net income	**344**	374	378	375	474
Basic and fully diluted earnings per common share *(Canadian dollars)*	**3.258**	3.562	3.182	—	—

[1] The results of operations and financial positions prior to April 1, 1999 may have been different if Hydro One had been a stand-alone corporation with its own management and capital structure, rather than a business unit of Ontario Hydro.

[2] Operation, maintenance and administration costs for *2002* included a charge of $25 million for a staff reduction program and for *1999* included a net charge of $24 million for a staff reduction program and the reversal of certain provisions.

[3] The transitional cost adjustment was a one-time charge that represented the difference between allowed costs specified in the OEB rate orders and costs incurred by Ontario Hydro during the first three months in 1999 that were allowed under the *Power Corporation Act*.

[4] The provincial debt guarantee fee was an annual fee equal to one-half of one percent (0.5%) of the total debt guaranteed by the Province outstanding as of the preceding December 31. This fee was eliminated effective April 1, 1999.

[5] The provisions of the *Electricity Act, 1998*, allow Hydro One to reduce employer contributions to the pension plan to the extent permitted under the *Pension Benefits Act* (Ontario), effective April 1, 1998. As a result, the deferred pension asset was increased by $204 million with a corresponding credit to 1998 operations.

[6] On September 15, 1999, Hydro One sold its 25% equity interest in Ontario Quartz A.V.V., resulting in a gain on sale.

[7] As of April 1, 1999, Hydro One is required to make payments in lieu of corporate taxes (see Notes 2 and 7).

Year ended December 31 (Canadian dollars in millions)	**2002**	2001	2000	1999	1998
Financial position data					
Total assets	**11,425**	11,251	9,997	10,000	9,435
Other financial data					
EBITDA[1]	**1,341**	1,575	1,275	1,292	1,333
Capital expenditures					
Transmission	**260**	274	280	527	171
Distribution[2]	**286**	247	152	180	188
Other	**24**	45	14	16	35
Ratios					
Net asset coverage on long-term debt[3]	**1.90**	1.88	1.90	1.85	1.45
Earnings coverage ratio[4]	**2.35**	2.55	2.57	2.19	1.82
U.S. GAAP *(Canadian dollars)*					
Net income	**347**	570	510	404	446
Comprehensive income[5]	**(74)**	570	510	404	446
Retained earnings[5]	**109**	582	270	362	—
Earnings coverage ratio[4]	**2.36**	2.52	2.20	2.26	1.77
Operating statistics					
Transmission					
Units transmitted (TWh)	**153.2**	146.9	146.9	144.1	143.0
System peak demand (MW)	**25,629**	25,209	23,428	23,435	22,445
Total transmission lines (circuit-kilometres)	**28,492**	28,587	28,490	28,889	29,006
Distribution					
Units distributed (TWh)	**27.1**	21.5	17.6	18.1	18.5
Total distribution lines (circuit-kilometres)	**122,830**	122,599	115,880	115,400	116,947
Customers[6]	**1,219,614**	1,193,089	957,474	953,900	977,835
Total regular employees[7]	**3,933**	4,815	4,468	5,052	5,221

[1] EBITDA represents income before financing charges, provision for payments in lieu of corporate income taxes, depreciation and amortization and does not include financing income.

[2] Capital expenditures exclude $468 million in 2001 and $25 million in 2000 associated with acquisitions of local distribution companies.

[3] The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[4] The earnings coverage ratio has been calculated as the sum of net income, gross interest expense (which excludes capitalized interest) and provision for payments in lieu of corporate income taxes divided by the sum of gross interest plus cumulative preferred dividends. On March 31, 2000, preferred dividends of $15 million were declared in respect of the nine months ended December 31, 1999. As a result, the earnings coverage ratio would have been 2.50 in 2000 (U.S. GAAP – 2.15) and 2.26 in 1999 (U.S. GAAP – 2.33) on the basis of dividends declared.

[5] Results for 2002 under U.S. GAAP reflect a minimum pension liability (see Note 22).

[6] As of April 1, 1999, Hydro One served approximately 954,000 retail customers. The reduction over 1998 was a result of statutory annexations under the Power Corporation Act of a small portion of facilities by several local distribution companies. Subsequent increases primarily reflect the acquisitions of local distribution companies.

[7] On March 1, 2002, approximately 770 regular employees were transferred to Inergi LP (see Note 19).

Glen Wright
Chair of the Board of Directors of the Corporation

W. Geoffrey Beattie
President, The Woodbridge Company Limited

Rita Burak
President and CEO, Network Executive Team, Management Consultants Inc.

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Dr. Murray B. Frum
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Corporate Director

Audit and Finance Committee

The Audit and Finance Committee is responsible for reviewing and making recommendations to the Board of Directors regarding the financing plans and objectives of the Company. The Audit and Finance Committee reviews the interim and annual Consolidated Financial Statements and related management's discussion and analysis disclosures, as well as financial statements issued in connection with any offerings of our securities as required by regulatory authorities. The committee also reviews the internal audit procedures of the Company and advises the Board of Directors on its auditing practices and procedures. The committee met five times in 2002.

Members:
Eileen Mercier, Chair
W. Geoffrey Beattie
Murray Elston
Dr. Murray Frum
Adam Zimmerman

Corporate Governance Committee

The Corporate Governance Committee is responsible for the Board's governance of the Company. It recommends issues to be discussed at meetings of the Board of Directors, annually reviews the mandates of each committee of the Board, monitors the quality of management's relationship with the Board and recommends suitable nominees for election to the Board of Directors. The committee met three times in 2002.

Members:
Adam Zimmerman, Chair
Eileen Mercier
Hon. Bob Rae
Blake Wallace

Human Resources and Public Policy Committee

The Human Resources and Public Policy Committee is responsible for reviewing the appropriateness of our current and future organizational structure, succession plans for corporate and divisional officers, the code of business conduct, the performance and remuneration of our senior executives, including recommending to the Board the remuneration of the President, and for identifying, assessing and providing advice to the Board of Directors on public affairs issues that have significant impact on us. The committee met five times in 2002.

Members:
Rita Burak, Chair
W. Geoffrey Beattie
Dr. Murray Frum
Hon. Bob Rae
Blake Wallace

Regulatory and Environment Committee

The Regulatory and Environment Committee is responsible for ensuring compliance with all applicable regulatory requirements and environmental legislation. The committee establishes compliance programs, policies, standards and procedures, reviews the Company's proposals for transmission and distribution rate applications, formulates contingency plans and reviews compliance actions and reports. The committee met five times in 2002.

Members:
Murray Elston, Chair
Rita Burak
Don MacKinnon
Kenneth Taylor

Health and Safety Committee

The Health and Safety Committee is responsible for occupational health and safety policies, standards, and programs, compliance with occupational health and safety legislation, policies and standards, and public health and safety issues. The committee met four times in 2002.

Members:
Don MacKinnon, Chair
Rita Burak
Kenneth Taylor
Blake Wallace

Corporate Address

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Investor Relations

(416) 345-6867
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Media Inquiries

(416) 345-6868
1-877-506-7584

Customer Inquiries

Power outage and emergency number: 1-800-434-1235
Residential, farm & small business accounts: 1-888-664-9376
Seasonal accounts: 1-877-543-3797
Large business accounts: 1-877-447-4412

Auditors

Ernst & Young LLP

This report was printed on acid-free and elemental chlorine-free papers using environmentally friendly low-solvent vegetable-based inks.

HYDRO ONE INC.
ANNUAL CONSOLIDATED FINANCIAL STATEMENTS

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HYDRO ONE INC.
MANAGEMENT'S REPORT

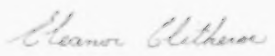
The accompanying Consolidated Financial Statements of Hydro One Inc. (Hydro One or the Company) are the responsibility of management and have been prepared in accordance with accounting principles generally accepted in Canada, and conform with accounting principles generally accepted in the United States, except as disclosed in Note 25 to the Consolidated Financial Statements. Hydro One applies accounting principles appropriate to its circumstances. The significant accounting policies followed by the Company are described in the summary of significant accounting policies contained in Note 2 to the Consolidated Financial Statements. The preparation of financial statements necessarily involves the use of estimates based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. The Consolidated Financial Statements have been properly prepared within reasonable limits of materiality and in light of information available up to February 13, 2002.

Management maintains a system of internal controls designed to provide reasonable assurance that the assets are safeguarded and that reliable financial information is available on a timely basis. The system includes formal policies and procedures and an organizational structure that provides for appropriate delegation of authority and segregation of responsibilities. An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit and Finance Committee of the Hydro One Board of Directors.

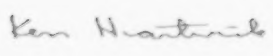
The Consolidated Financial Statements have been examined by Ernst & Young LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with generally accepted accounting principles. The Auditors' Report, which appears on page 3, outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

On behalf of Hydro One Inc.'s Management:



Eleanor R. Clitheroe
President and Chief Executive Officer



Kenneth M. Hartwick
Chief Financial Officer & Senior Vice President Finance

HYDRO ONE INC.
AUDITORS' REPORT

To the Shareholder of Hydro One Inc.:

We have audited the Consolidated Balance Sheets of Hydro One Inc. (the Company) as at December 31, 2001 and December 31, 2000, and the Consolidated Statements of Operations, Retained Earnings and Cash Flows of the Company for each of the years in the three-year period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian and United States generally accepted auditing standards for 2001 and 2000 and Canadian generally accepted auditing standards for 1999. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and December 31, 2000, the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2001, in accordance with Canadian generally accepted accounting principles.

As described in the Summary of Significant Accounting Policies – Environmental Costs, effective January 1, 2001, the Company changed its policy for estimated future expenditures to remediate past environmental contamination.

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants
Toronto, Canada

February 13, 2002

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

Year ended December 31 (Canadian dollars in millions)	2001	2000	1999
Revenues			
Transmission *(Note 18)*	1,259	1,260	1,237
Distribution *(Note 18)*	2,158	1,703	1,793
Other	49	32	95
	3,466	2,995	3,125
Costs			
Operation, maintenance and administration *(Note 5)*	824	863	863
Purchased power *(Note 18)*	1,267	859	939
Depreciation and amortization *(Note 6)*	384	348	342
Transitional cost adjustment *(Note 7)*	-	-	55
Provincial debt guarantee fee *(Note 18)*	-	-	8
	2,475	2,070	2,207
Other income			
Gain on sale of investment *(Note 8)*	-	-	32
Income before financing charges and provision for payments in lieu of corporate income taxes	991	925	950
Financing charges *(Notes 9 and 18)*	350	340	381
Income before provision for payments in lieu of corporate income taxes	641	585	569
Provision for payments in lieu of corporate income taxes *(Notes 10 and 18)*	267	207	194
Net income	374	378	375
Basic and fully diluted earnings per common share *(Canadian dollars) (Note 17)*	3.562	3.182	-

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 (Canadian dollars in millions)	2001	2000	1999
Retained earnings, January 1	241	265	-
Net income (from April 1, 1999)	374	378	265
Dividends	(258)	(402)	-
Retained earnings, December 31	357	241	265

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS

December 31 (Canadian dollars in millions)	2001	2000
Assets		
Current assets		
Accounts receivable (net of allowance for doubtful accounts - $12 million; 2000 - $10 million)	538	511
Materials and supplies	56	65
	594	576
Fixed assets *(Note 11)*		
Fixed assets in service	13,335	12,375
Less: accumulated depreciation	4,581	4,108
	8,754	8,267
Construction in progress	349	252
	9,103	8,519
Other long-term assets		
Deferred pension asset *(Note 13)*	847	452
Regulatory assets *(Note 12)*	519	352
Goodwill *(Note 4)*	133	6
Long-term accounts receivable and other assets	22	78
Deferred debt costs	13	14
	1,534	902
Total assets	11,231	9,997

See accompanying notes to Consolidated Financial Statements

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (continued)

December 31 (Canadian dollars in millions)	2001	2000
Liabilities		
Current liabilities		
Bank indebtedness	24	24
Accounts payable and accrued charges *(Note 18)*	691	357
Accrued interest	57	64
Short-term notes payable *(Note 14)*	410	130
Long-term debt payable within one year *(Note 14)*	443	474
	1,625	1,049
Long-term debt *(Note 14)*	4,079	3,972
Other long-term liabilities		
Regulatory liability *(Note 12)*	847	452
Employee future benefits other than pension *(Note 13)*	510	509
Environmental liabilities *(Note 16)*	158	-
Long-term accounts payable and accrued charges	18	15
	1,533	976
Total liabilities	7,237	5,997
Contingencies and commitments *(Notes 15, 20, 21 and 23)*		
Shareholder's equity *(Notes 3 and 17)*		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,436
Retained earnings	357	241
Total shareholder's equity	3,994	4,000
Total liabilities and shareholder's equity	11,231	9,997

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

Sir Graham Day
Chair of the Board of Directors

Eleanor R. Clitheroe
President and Chief Executive Officer

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in millions)	2001	2000	1999
Operating activities			
Net income	374	378	375
Adjustments for non-cash items:			
Depreciation and amortization (net of removal costs)	352	324	324
Transitional cost adjustment	-	-	55
Gain on sale of investment	-	-	(32)
	726	702	722
Changes in non-cash balances related to operations *(Note 19)*	188	23	118
Net cash generated from operations	914	725	840
Financing activities			
Debt for long-term financing:			
Issued	550	1,000	194
Retired	(474)	(1,399)	(362)
Debt for short-term financing	280	130	-
Deferred debt costs	1	(12)	(2)
Dividends paid	(258)	(398)	-
Net cash generated from (used in) financing activities	99	(679)	(170)
Investing activities			
Fixed assets	(566)	(446)	(529)
Acquisitions of municipal electricity utilities	(475)	(23)	-
Proceeds on disposal of fixed assets and investments	-	-	245
Other assets	28	(69)	43
Net cash used in investing activities	(1,013)	(538)	(241)
Net change in cash and cash equivalents	-	(492)	429
Cash and cash equivalents, January 1	(24)	468	39
Cash and cash equivalents, December 31 *(Note 19)*	(24)	(24)	468

See accompanying notes to Consolidated Financial Statements.

1. INCORPORATION AND COMMENCEMENT OF OPERATIONS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and issued 10 common shares for nominal consideration, and is wholly-owned by the Province of Ontario (the Province). As part of the reorganization of Ontario Hydro under the *Electricity Act, 1998*, and the related restructuring of the electricity industry in Ontario, Hydro One acquired and assumed certain assets, liabilities, rights and obligations of the electricity transmission, distribution and energy services businesses of Ontario Hydro on April 1, 1999, and commenced operations on that date. In exchange, the Company issued debt and a promissory note, which was assumed by the Province in connection with the capitalization of the Company on March 31, 2000 (see Notes 3 and 17).

The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly-owned subsidiaries: Hydro One Networks Inc., Hydro One Network Services Inc., Ontario Hydro Energy Inc. (Ontario Hydro Energy), Hydro One Remote Communities Inc., Hydro One Brampton Inc. (Hydro One Brampton), Hydro One Markets Inc., Hydro One Telecom Inc., Ontario Hydro Delivery Services Company Inc. and Ontario Hydro International Inc. (Ontario Hydro International). Effective January 1, 2002, Ontario Hydro International was wound-up.

Basis of Accounting

The Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP) and conform with accounting principles generally accepted in the United States (U.S. GAAP), except as disclosed in Note 25.

The results of operations and cash flows presented in these Consolidated Financial Statements for the 3 months prior to April 1, 1999, have been recorded in Hydro One's Consolidated Financial Statements on the same basis and in the same periods as originally recorded by Ontario Hydro. These results were determined through specific identification of revenues and expenses and also through an allocation of certain common financial statement accounts and items of Ontario Hydro.

Rate-setting

The *Ontario Energy Board Act, 1998* gave the OEB increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or fix rates for licensed transmitters and distributors of electricity, the power to provide continued rate protection for rural and remote electricity consumers, and the responsibility for ensuring that distribution companies fulfill obligations to connect and service customers. Prior to April 1, 1999, Ontario Hydro was governed by the *Power Corporation Act*, which provided it with broad powers to generate, supply and deliver electricity throughout Ontario.

The transitional rate orders issued by the OEB effective April 1, 1999, which approved the transmission and distribution revenue requirements for 1999 and 2000, were designed to permit these regulated businesses to recover their allowed costs and to earn a forecasted annual rate of return of 9.35% for 1999 on the average common equity deemed, for regulatory purposes, to be allocated to such businesses. For 2000, the OEB adjusted the rate of return to 9.88% to reflect higher forecasted interest rates for that year. Although Hydro One did not commence operations as a stand-alone enterprise separate from Ontario Hydro until April 1, 1999, the transitional rate orders formed the basis of revenue recognition for the 3 months ended March 31, 1999, consistent with a revenue allocation agreement among the successor corporations of Ontario Hydro.

Revenue allocation based on the transitional rate order will continue to apply to the transmission business until Open Access, which the Province announced will be May 1, 2002. Following Open Access, the unbundled transmission rates approved by the OEB on January 15, 2001 will be implemented. These rates are based on the revenue requirement approved by the OEB under the transitional rate order for the year 2000.

The transitional bundled distribution rate order for the distribution business was extended during 2001 and then superceded on May 31, 2001 by a rate order incorporating a change to the wholesale cost of power. Effective June 1, 2001, distribution revenues recovered a 0.7 cent per kWh increase in the wholesale cost of power. Effective October 1, 2001, the Company's cost of power for its traditional customers was further increased by 1.15 cents per kWh to be consistent with the rate paid by other large distribution companies. The October increase, with line losses, would have resulted in an increase of 13.1% in customer bills. In order to limit the impact of this increase on the average total bill for retail customers, the Company proposed to phase in the cost of power increase by seeking increases of 4.0% on October 1, 2001 and further increases of 2.8% on each of March 1, 2002 and March 1, 2003. The Company reserved the right to return to the OEB with a proposal in respect of the remainder. A rate mitigation plan to address the revenue shortfall has been put in place. On September 19, 2001, the OEB issued an interim approval of the first phased increase, effective October 1, 2001; and on January 11, 2002 an interim approval was issued for the second phased increase, effective March 1, 2002. The OEB's review of Hydro One's unbundled distribution rates for the period commencing with Open Access is underway.

The following regulatory treatments have resulted in accounting treatments differing from Canadian GAAP for enterprises operating in a non-rate-regulated environment:

I. Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One recorded a regulatory asset in the original amount of $419 million to reflect this regulatory treatment;

II. Expenses incurred to align systems and practices with the requirements of the future competitive electricity market in Ontario (Market Ready costs) have been deferred in accordance with the initial criteria set out in the OEB's *Electricity Distribution Rate Handbook* and the *Accounting Procedures Handbook for Electric Distribution Utilities*. In the absence of such regulation, these costs would have been expensed when incurred under Canadian GAAP. The Company has applied for interim recovery of a portion of the costs and will apply for recovery of the remaining costs once the guidelines and timetable for this process have been established by the OEB. The OEB has the discretion to examine and assess the extent and timing of recovery of these Market Ready costs;

III. Effective January 1, 2001, Hydro One began to provide for estimated future expenditures required to remediate past environmental contamination. Because such expenditures are recoverable through rates, the Company recorded a regulatory asset in the original amount of $190 million. With the exception of that portion of the regulated asset relating to certain distribution expenditures, this regulatory asset, including future interest accretion, is expected to be amortized over the period to 2020 on a basis substantially consistent with the pattern of actual expenditures. Under the terms of a rate mitigation plan submitted to the OEB by Hydro One, that portion of the regulatory asset related to distribution expenditures for 2001 and 2002 will be amortized to results of operations on a straight-line basis over the period 2003 to 2020, inclusive. The OEB has the discretion to examine and assess the extent and timing of recovery of these environmental costs;

IV. In accordance with the transitional rate orders approved by the OEB, pension costs are recorded in the results of operations when employer contributions are paid to the pension fund rather than on the accrual basis. As a result, a regulatory liability has been recorded in an amount equal to the deferred pension asset; and

V. The Company provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the OEB.

Revenue Recognition and Allocation

Until Open Access, traditional electricity customers will continue to pay bundled rates for electricity. Revenues are being collected, pooled and allocated to the successor corporations of Ontario Hydro consistent with a revenue allocation agreement among such corporations.

The revenue requirement for the transmission business is collected through the revenue allocation agreement and is recognized in accordance with the terms of the agreement. The revenue requirement is based on the transitional rate orders issued by the OEB. Distribution revenues attributable to the sale and delivery of electricity represent actual, rather than allocated, revenues, and are recognized as power is delivered to customers. Because customer meters are not generally read on a monthly basis, it is necessary to estimate the monthly revenue for the period based on wholesale power purchases.

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which is collected through the revenue allocation agreement and recognized in accordance with the terms of the agreement. The current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Transmission, distribution and other segment revenues also include revenue related to sales of services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate taxes to Ontario Electricity Financial Corporation (OEFC), commencing April 1, 1999. These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) as modified by the *Electricity Act, 1998*, and related regulations.

The Company provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Hydro One at that time.

Materials and Supplies

Materials and supplies represent spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at the lower of average cost and replacement cost.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the approved allowance for funds used during construction applicable to capital construction activities within regulated businesses or interest applicable to capital construction activities within unregulated businesses.

Fixed assets in service consist of transmission, distribution, communication, and administration and service assets. Fixed assets also include future use assets such as land and capitalized development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, such as transformers, circuit breakers and switches.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Construction in Progress

Financing costs are capitalized on fixed assets under construction within regulated businesses based on the allowance for funds used during construction and within unregulated businesses using an interest capitalization rate that approximates the average cost of all long-term funds borrowed. The regulated and unregulated rates were the same for the period 1999 to 2001 (2001 - 8.1%; 2000 - 8.0%; 1999 - 7.9%).

Impairment of Fixed Assets

In the event that facts and circumstances indicate that a fixed asset may be impaired, an evaluation of recoverability is performed. For purposes of such an evaluation, the estimated future undiscounted cash flows associated with the fixed asset are compared to the asset's carrying amount to determine if a write-down is required.

Depreciation

The capital costs of fixed assets are depreciate d on a straight-line basis, except for transport and work equipment and personal computers, which are depreciated on a declining balance basis.

Depreciation rates for the various classes of assets are based on their estimated service lives. The average estimated service lives and service life ranges of fixed assets are:

	Estimated service lives (years)	
	Range	Average
Transmission	12 - 100	57
Distribution	15 - 55	41
Communication	7 - 40	22
Administration and service	5 - 50	42

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining service life basis from the year the changes can first be reflected in rates.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, group life insurance, health care, workers' compensation and long-term disability.

In accordance with the OEB's transitional rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). As a result, a regulatory liability is recorded in an amount equal to the deferred pension asset. The deferred pension asset arises as a result of the cumulative difference between employer contributions and pension costs. Pension plan assets, consisting primarily of listed equity securities, and corporate and government debt securities, are valued using fair values. Actuarial valuations are conducted at least every three years.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or are capitalized as part of the cost of fixed assets.

Goodwill

Goodwill represents the cost of acquired municipal electricity utilities in excess of fair value of the net identifiable assets purchased.

Goodwill arising from acquisitions completed on or before June 30, 2001 is amortized on a straight-line basis over 20 years. Goodwill arising from acquisitions completed subsequent to June 30, 2001 is not amortized in accordance with the Canadian Institute of Chartered Accountants' (CICA) Handbook Section 3062, *Goodwill and Other Intangible Assets*. Effective January 1, 2002, the amortization of goodwill will cease.

The carrying value of goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. In the event goodwill may be impaired, an evaluation of recoverability is performed based on estimated future undiscounted cash flows, as well as other factors.

Deferred Debt Costs

Deferred debt costs include the unamortized amounts of debt discounts or premiums arising from the issuance of debt and other costs. Deferred debt costs are amortized over the period to maturity of the debt on an annuity basis.

Environmental Costs

Hydro One changed its accounting policy for estimated future expenditures to remediate past environmental contamination. Prior to January 1, 2001, Hydro One accounted for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, on an as incurred basis. Effective January 1, 2001, Hydro One changed its accounting policy for these legacy obligations and recognized a liability for the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, no charge was made to 2001 results of operations. Instead, a regulatory asset was recognized to reflect the future recovery of these costs from customers (see Notes 12 and 16). Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

Foreign Currency Translation

Current monetary assets and liabilities in foreign currencies are translated to Canadian currency at year-end rates of exchange and the resulting exchange gains or losses are credited or charged to results of operations.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future regulatory decisions.

3. REORGANIZATION OF ONTARIO HYDRO

On March 31, 2000, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares and 99,990 common shares. As consideration, the Province assumed Hydro One's obligations including accrued interest from April 1, 1999 under a promissory note and, in connection with the assumption of the Company's obligations by the Province, OEFC released Hydro One, effective as of March 31, 2000, from its obligations under the promissory note.

The capitalized value of the Company as at April 1, 1999 was determined as follows:

(Canadian dollars in millions)	
Excess of assets over liabilities, March 31, 1999	2,516
Adjustments:	
Elimination of allocated long-term debt from Ontario Hydro	5,382
Elimination of allocated short-term notes from Ontario Hydro	533
Elimination of allocated accrued interest	143
Elimination of allocated deferred debt costs	(228)
Debt issued effective April 1, 1999	(4,845)
	985
Regulatory asset - employee future benefits other than pension	419
Adjustment to deferred pension asset	164
Regulatory liability – deferred pension	(386)
Other net adjustments	61
	3,759
Represented by:	
Shares to be issued (represented by promissory note)	3,759

The purchase of the transmission, distribution and energy services businesses from the related party, OEFC, was recorded at the exchange amount of $8.6 billion, which approximated the book values of the assets acquired and liabilities assumed on April 1, 1999, and, in the current regulatory environment, approximated their fair value.

The actual net amount of assets and liabilities acquired on April 1, 1999 was less than estimates by $122 million. This excess of equity and liabilities over assets was originally recorded as an account receivable. In December 2001, Hydro One and the Province reached an agreement to settle the $122 million account receivable as a post-closing adjustment through shareholder's equity. The adjustment to shareholder's equity has been applied as a reduction of common share equity.

4. ACQUISITIONS OF MUNICIPAL ELECTRICITY UTILITIES

During 2001, Hydro One acquired the outstanding shares or assets of 71 (2000 - 16) municipal electricity utilities for cash consideration of approximately $475 million (2000 - $23 million). Net identifiable assets acquired amounted to approximately $347 million (2000 - $17 million), representing assets of $416 million (2000 - $20 million) and liabilities of $69 million (2000 - $3 million). Based on the allocation of the purchase price, the transactions resulted in goodwill of $128 million (2000 - $6 million). These acquisitions were accounted for by the purchase method with the acquired companies' results of operations being included in the Consolidated Statement of Operations from the dates of acquisition.

Goodwill amortized during 2001 was $1 million (2000 - $nil). Goodwill recognized after June 30, 2001, which is not subject to amortization, was $93 million.

5. OPERATION, MAINTENANCE AND ADMINISTRATION

In November 1999, Hydro One approved a staff reduction program intended to reduce cost levels and recorded a provision in 1999 in the amount of $60 million. Costs in the amount of $53 million were charged to the provision in 2000 and $2 million was charged in 2001. In 2000, $5 million of the provision was reversed as a credit to the results of operations. In 1999, Hydro One also re-evaluated the need for some provisions previously recognized by Ontario Hydro and assumed by the Company on April 1, 1999. Remaining provisions of $36 million associated with an involuntary staff reduction program and surplus real estate were reversed as a credit to the results of operations in 1999.

6. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in millions)	2001	2000	1999
Depreciation of fixed assets in service	302	280	270
Fixed asset removal costs	32	24	18
Amortization of regulatory and other assets	50	44	54
	384	348	342

7. TRANSITIONAL COST ADJUSTMENT

The transitional cost adjustment represents the difference between allowed costs specified in the OEB transitional rate orders, and costs incurred by Ontario Hydro during the first three months in 1999 that were allowed under the *Power Corporation Act*. Costs included in Hydro One's revenue requirement were higher due to payments in lieu of corporate taxes and an amount for amortization relating to the recovery of employee future benefits other than pension costs. These additional costs were partially offset by reduced financing charges resulting from lower debt balances that reflected the new capital structure of the Company and lower interest rates as well as the elimination of the provincial debt guarantee fee levied by the Province. The transitional cost adjustment was a non-recurring charge.

The following summarizes the components of the transitional cost adjustment for the three months ended March 31, 1999:

(Canadian dollars in millions)	1999
Depreciation and amortization	10
Payments in lieu of capital tax	6
Payments in lieu of corporate income taxes	87
Provincial debt guarantee fee	(8)
Financing charges	(40)
	55

8. ONTARIO HYDRO INTERNATIONAL INC.

On September 15, 1999, Hydro One's subsidiary, Ontario Hydro International, sold its 25% equity interest in Ontario Quinta A.V.V. (Ontario Quinta), resulting in a gain before income taxes of $32 million. At the time of the sale, Ontario Quinta held a 60% interest in Luz del Sur S.A.A., an electricity distribution company serving southern Lima, Peru, and a 64% interest in Tecsur S.A.A., a utility maintenance and construction company also operating in Peru.

9. FINANCING CHARGES

Year ended December 31 (Canadian dollars in millions)	2001	2000	1999
Interest on short-term notes payable	7	2	-
Interest on long-term debt payable	369	377	411
Less: Interest charged to construction in progress	(21)	(22)	(18)
Interest earned on investments	(5)	(17)	(12)
	350	340	381

10. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31 (Canadian dollars in millions)	2001	2000	1999
Income before provision for PILs	641	585	569
PILs included in the transitional cost adjustment *(Note 7)*	-	-	87
Less: Income before provision for PILs for the period January 1 to March 31, 1999	-	-	(197)
Adjusted income before provision for PILs	641	585	459
Federal and Ontario statutory income tax rate	41.74%	43.95%	44.62%
Provision for PILs at statutory rate	268	257	205
Increase (decrease) resulting from:			
The application of the income taxes payable method to the regulated businesses:			
Net temporary differences:			
Capital cost allowance in excess of depreciation and amortization	(20)	(44)	(50)
Environmental expenditures	(10)	-	-
Interest capitalized for accounting purposes but deducted for tax purposes	(8)	(10)	(7)
Employee future benefits other than pension expense in excess of (lower than) cash payments	6	(4)	3
Charge for staff reduction program in excess of (lower than) cash payments	-	(23)	27
Other	14	8	-
Net temporary differences	(18)	(73)	(27)
Permanent differences:			
Large corporations tax	16	15	11
Other	1	8	5
Net permanent differences	17	23	16
Provision for PILs	267	207	194
Effective income tax rate	41.65%	35.38%	42.27%

Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2001, future income tax liabilities of $105 million (2000 - $80 million), based on substantively enacted income tax rates, have not been recorded. Hydro One was not subject to PILs prior to April 1, 1999.

11. FIXED ASSETS

December 31 (Canadian dollars in millions)	Fixed assets in service	Accumulated depreciation	Construction in progress	Total
2001				
Transmission	8,150	2,527	178	5,801
Distribution	4,134	1,486	53	2,701
Communication	443	214	39	268
Administration and service	608	354	79	333
	13,335	4,581	349	9,103
2000				
Transmission	7,968	2,493	144	5,619
Distribution	3,441	1,097	85	2,429
Communication	383	194	5	194
Administration and service	583	324	18	277
	12,375	4,108	252	8,519

Financing costs are capitalized on fixed assets under construction, including allowance for funds used during construction on regulated assets and interest on unregulated assets, and were $21 million in 2001 (2000 - $22 million; 1999 - $18 million).

Hydro One customer contributions are netted against the cost of the asset. Cumulative customer contributions in aid of construction received by Hydro One, net of amortization, except for Hydro One Brampton, were $45 million (2000 - $49 million) for transmission and $207 million (2000 - $215 million) for distribution. Hydro One's subsidiary, Hydro One Brampton, consistent with other Ontario municipal electricity utilities, records contributions in aid of construction received prior to January 1, 2000 within fixed assets on a gross basis and depreciates these amounts over the remaining service lives of the assets.

12. REGULATORY ASSETS AND LIABILITY

Regulatory assets and liabilities can arise as a result of the rate-making process. As described in Note 2, Hydro One has recorded the following regulatory assets and liability, which are presented net of accumulated amortization of $132 million (2000 - $84 million).

December 31(Canadian dollars in millions)	2001	2000
Regulatory assets:		
Employee future benefits other than pension	293	335
Environmental	195	-
Market Ready	25	17
Other	6	-
Total regulatory assets	519	352
Regulatory liability:		
Deferred pension	847	452
Total regulatory liability	847	452

Hydro One's total deferred Market Ready costs of $89 million (2000 - $42 million), include the above Market Ready regulatory asset of $25 million (2000 - $17 million), and $64 million (2000 - $25 million) in information systems costs currently classified as construction in process.

13. EMPLOYEE FUTURE BENEFITS

Hydro One established a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton, on January 1, 2000. Until that date, employees and pensioners continued to participate in the Ontario Electricity Financial Corporation Pension Plan (OEFC Pension Plan), formerly the Ontario Hydro Pension and Insurance Plan. The OEFC Pension Plan transferred assets and liabilities to the successor plans, including the pension plan of Hydro One, in 2001.

Employees of Hydro One Brampton participate in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector pension fund, which is a defined contribution plan. As Hydro One Brampton has been under a contribution holiday since August, 1998, no contributions have been made to the pension fund.

Effective January 1, 2000, Hydro One adopted the CICA's recommendations relatedl to employee future benefits. The rate used to discount future pension benefits changed from a long-term average rate of return to a market-based interest rate. Hydro One has applied the recommendations retroactively but has not restated individual comparative periods. The cumulative effect of this adoption was a $211 million increase to the dieferred pension asset and the regulatory liability.

Prior to January 1, 2002, Hydro One self-insured its workers' compensation liability. Effective January 1, 2002, the Company's status under the *Workplace Safety & Insurance Act, 1997* will change, and as a result Hydro One will be required to pay premiums to the Workplace Safety & Insurance Board. In connection with the change in employer status, the Company settled its outstanding workers' compensation liability in 2001.

	Pension		Employee Future Benefits other than Pension	
Year ended December 31 (Canadian dollars in millions)	**2001**	**2000**	**2001**	**2000**
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	3,804	3,690	547	434
Adjustment related to adoption of new standard[1]	-	(230)	-	-
Accrued benefit obligation, January 1, as adjusted	3,804	3,460	547	434
Past service costs from plan amendments	23	-	3	14
Current service cost	64	55	17	15
Interest cost	258	246	37	35
Benefits paid	(220)	(199)	(30)	(39)
Settlement of workers' compensation liability	-	-	(29)	-
Acquisitions of municipal electricity utilities	-	-	10	-
Net actuarial loss	237	242	132	85
Staff reduction program	-	-	-	3
Accrued benefit obligation, December 31	4,166	3,804	687	547
Change in plan assets				
Fair value of plan assets, January 1	4,407	4,296	-	-
Actual return on plan assets	(88)	301	-	-
Employer contributions	15	-	-	-
Employees' contributions	12	16	-	-
Benefits paid	(220)	(199)	-	-
Administrative expenses	(6)	(7)	-	-
Fair value of plan assets, December 31	4,120	4,407	-	-
Funded status				
(Unfunded benefit obligation) funded excess	(46)	603	(687)	(547)
Unamortized net actuarial losses	872	270	142	-
Unamortized past service costs	21	-	8	11
Deferred pension asset (accrued benefit liability)	847	873	(537)	(536)
Valuation allowance[2]	-	(421)	-	-
Deferred pension asset, net of valuation allowance (accrued benefit liability)	847	452	(537)	(536)
Less: current portion	-	-	27	27
Deferred pension asset, net of valuation allowance (long-term liability)	847	452	(510)	(509)

1 Includes past service costs from plan amendments of $63 million recognized on adoption of new standard.

2 The valuation allowance reduces the deferred pension asset to the maximum future benefit Hydro One expects to realize from the plan surplus.

Year ended December 31 (Canadian dollars in millions)	Pension 2001	Pension 2000	Pension 1999	Employee Future Benefits Other than Pension 2001	Employee Future Benefits Other than Pension 2000	Employee Future Benefits Other than Pension 1999
Components of net periodic benefit cost						
Current service cost, net of employee contributions	49	39	58	17	15	16
Interest cost	258	246	215	37	35	29
Expected return on plan assets	(312)	(316)	(275)	-	-	-
Amortization of net actuarial losses (gains)	29	-	(19)	-	(2)	7
Amortization of past service costs	2	-	-	1	1	-
Staff reduction program	-	-	165	-	(4)	-
Change in valuation allowance	(421)	31	-	-	-	-
Adjustment due to transitional rate orders *(Note 2)*	-	-	(141)	-	-	-
Net periodic benefit cost	(395)[1]	-	3	55	45	52
Capitalized as part of the cost of fixed assets	-	-	1	22	21	22
Charged to operations	-	-	2	33	24	30
Effect of 1% increase in health care cost trends on:						
Accrued benefit obligation, December 31	-	-	-	72	54	35
Net periodic benefit cost	-	-	-	5	5	4
Effect of 1% decrease in health care Cost trends on:						
Accrued benefit obligation, December 31	-	-	-	(58)	(44)	(29)
Net periodic benefit cost	-	-	-	(4)	(4)	(3)
Significant assumptions						
Weighted-average discount rate	6.50%	6.75%	6.50%	6.66%	6.88%	7.38%
Rate of compensation scale escalation	3.50%	3.25%	3.50%	3.50%	3.25%	3.50%
Rate of return on plan assets	7.50%	7.75%	7.25%	-	-	-
Rate of cost of living increase	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Average remaining service life of employees (years)	12	14	11	12	14	11
Rate of increase in long-term medical costs[2]	-	-	-	4.50%	4.50%	4.50%
Rate of increase in dental costs[3]	-	-	-	3.50%	3.50%	3.50%

1 Adjustment to regulatory liability of corresponding amount, therefore no impact on operations.
2 10.00% grading down to 4.5% after eight years (2000 – 9.00% grading down to 4.50% after five years; 1999 – 7.20% grading down to 4.50% after three years).
3 5.00% for five years, 3.5% thereafter (2000 – 3.50% per annum; 1999 – 3.50% per annum).

14. DEBT

December 31 (Canadian dollars in millions)	2001	2000
Short-term notes payable	410	130
Long-term debt		
Notes payable to OEFC	2,972	3,446
6.94% debentures due 2005	200	200
7.15% debentures due 2010	400	400
6.40% note due 2011	250	-
7.35% debentures due 2030	400	400
6.93% note due 2032	300	-
	4,522	4,446
Less: long-term debt payable within one year	443	474
Long-term debt	4,079	3,972

Short-term debt represents promissory notes issued pursuant to the Company's commercial paper program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days and with a weighted-average interest rate of 2.16% (2000 - 5.75%).

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding on Notes and Debentures *(Canadian dollars in millions)*	Principal Outstanding on Notes Payable to OEFC *(Canadian dollars in millions)*	Weighted-Average Interest Rate *(Percent)*
1 year	-	443	11.0
2 years	-	651	7.2
3 years	-	682	6.8
4 years	200	507	7.7
5 years	-	589	10.3
	200	2,872	8.4
6 – 10 years	650	100	7.6
Over 10 years	700	-	7.2
	1,550	2,972	8.0

Hydro One has committed and unused revolving credit agreements with a syndicate of banks in the amount of $500 million which matures in 2002 and $250 million which matures in 2005. If used, interest on the lines of credit would apply based on Canadian benchmark rates. These credit agreements support the Company's commercial paper program. As at December 31, 2001, the Company also had $108 million in letters of credit outstanding.

15. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of long-term debt, based on year-end quoted market prices for same or similar debt of the same remaining maturities, is provided in the following table:

December 31 (Canadian dollars in millions)	2001		2000	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	4,522	4,956	4,446	4,873

Hydro One may enter into forward pay fixed interest rate swap agreements to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. When the hedged borrowing occurs, Hydro One terminates the hedge either by terminating the interest rate swap or by entering into an offsetting swap agreement. As at December 31, 2001, offsetting interest swap agreements were outstanding with the same counter-party having notional principal amounts of $167 million (2000 - $nil) and a fair value of $nil. The swap agreements mature in 2011.

Hydro One's unregulated retail subsidiary, Ontario Hydro Energy, offers fixed-price full requirements electricity contracts to residential consumers in Ontario. The sales contracts have terms up to five years. Contracts signed to date will become effective on or shortly after May 1, 2002, the date of Open Access in Ontario. Under the rules of Open Access, Ontario Hydro Energy will be required to purchase the energy used each hour by its customers at a price equal to the hourly spot price in Ontario's wholesale electricity market. To hedge the exposure to spot prices, Ontario Hydro Energy enters into financial electricity swap agreements under which it pays the counter-party a fixed price per MWh and receives the Ontario spot price. At December 31, 2001, Ontario Hydro Energy had swap agreements with an aggregate notional amount of 906,000 MWh, at a fixed price ranging from $45 to $50 per MWh, through April 2007. Based on the Company's best estimate of forward electricity prices for Ontario, the fair value of the swaps is immaterial.

In addition, Ontario Hydro Energy has entered into a number of long-term gas purchase and transportation agreements in the normal course of business to supply its retail gas contracts. The annual commitments under the gas purchase contracts in each of the five years subsequent to December 31, 2001 are as follows: 2002 - $7 million; 2003 - $7 million; 2004 - $7 million; 2005 - $7 million; and 2006 - $6 million.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2001, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers consistent with the revenue allocation agreement among the successor corporations. As a result, Hydro One did not earn a significant amount of revenue from any single customer. As at December 31, 2001, there were no significant balances of accounts receivable due from any single customer.

The Company will continue to use derivative instruments to manage interest rate risk and commodity price risk. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. Hydro One monitors and minimizes credit risk through various techniques including dealing with highly-rated counter-parties, limiting total exposure levels with individual counter-parties and by entering into master agreements which enable net settlement.

16. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	2001
Environmental liabilities	174
Less: current portion	(16)
	158

Hydro One changed its accounting policy for environmental obligations on January 1, 2001 and recognized a liability for the present value of the estimated future expenditures to assess and remediate contaminated lands and to manage PCB contamination. As at January 1, 2001, the total estimated future expenditures, based on existing regulations, amounted to $95 million for land assessment and remediation and $170 million for PCB management. These amounts, expected to be incurred over the period 2001 to 2020 inclusive, were discounted using a 6.25% interest rate, resulting in an opening January 1, 2001 environmental obligation of $190 million. During 2001, expenditures of $26 million were charged to this provision and $10 million of interest was added resulting in a December 31, 2001 balance of $174 million. Hydro One's estimate of future environmental expenditures did not change during 2001.

There are uncertainties in estimating future environmental costs due to potential external events such as tightening regulations and advances in remediation technologies. Hydro One continuously reviews factors affecting its cost estimates as well as the environmental condition of its various properties. The costs for investigation or remediation of such properties may differ from currently estimated amounts depending on the results of such reviews.

Consolidated balance sheets for dates before 2001 have not been restated to reflect the new policy, as it was not in effect for rate purposes in earlier periods.

17. SHARE CAPITAL

Common and Preferred Shares

On March 31, 2000, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares with a redemption value of $25.00 per share, and 99,990 common shares, bringing the total number of outstanding common shares to 100,000. The Company is authorized to issue an unlimited number of preferred and common shares. In December 2001, Hydro One and the Province reached an agreement to settle the $122 million account receivable as a post-closing adjustment through shareholder's equity (see Note 3). The adjustment to shareholder's equity has been applied as a reduction of common share equity. The Province is expected to pass a special resolution to reduce stated capital for legal purposes by $122 million effective December 31, 2001.

The preferred shares are entitled to an annual cumulative dividend of $18 million, which is payable on a quarterly basis. The preferred shares are redeemable at the option of the Province at a price of $25.00 per share plus any accrued and unpaid dividends if the Province sells a number of the Company's common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the Company's common shares. Hydro One may elect to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yields for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority to the common shares upon liquidation.

Dividends

Common dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2001, preferred dividends in the amount of $18 million (2000 - $31 million) and common dividends in the amount of $240 million (2000 - $371 million) were declared. Dividends declared during 2000 include $13 million in preferred dividends and $158 million in common dividends that were declared in respect of the nine months ended December 31, 1999.

Earnings per Share

Earnings per share is calculated as net income during the year, after cumulative preferred dividends, divided by the weighted-average number of common shares outstanding during the year. Earnings per share for 1999 and 2000 reflect the issuance of common shares on March 31, 2000.

18. RELATED PARTY TRANSACTIONS

Prior to April 1, 1999, Hydro One, Ontario Power Generation Inc. (OPG), the Electrical Safety Authority (ESA) and the Independent Market Operator (IMO) were, in effect, business units of Ontario Hydro. Upon the reorganization of Ontario Hydro, OPG, the ESA and the IMO became related parties of Hydro One because all of these entities are controlled by the Province.

Hydro One receives revenue for transmission services consistent with the revenue allocation agreement (see Note 2). Transmission revenue for 2001 includes $1,213 million (2000 - $1,182 million; 1999 - $1,164 million) related to these services.

Hydro One receives a portion of its distribution revenue consistent with the revenue allocation agreement that will terminate upon Open Access (see Note 2). Under this agreement, distribution revenue for 2001 includes $52 million related to these services (2000 - $59 million; 1999 - $106 million).

Hydro One also receives revenue related to the supply of electricity to the 19 remote northern communities consistent with the revenue allocation agreement (see Note 2). Distribution revenue for the year ended December 31, 2001 includes $21 million (2000 - $17 million; 1999 - $15 million) related to these services.

Hydro One receives amounts for rural rate protection from customer revenue collected by the IMO (the Province prior to April 1, 1999) (see Note 2). Distribution revenue for 2001 includes $127 million (2000 - $127 million; 1999 - $127 million) related to this program, of which $5 million (2000 - $7 million; 1999 - $7 million) was paid to municipal electricity utilities in respect of annexation agreements.

Hydro One purchased power from OPG in the amount of $1,265 million in 2001 (2000 - $857 million; 1999 - $900 million). Hydro One has also entered into electricity swaps with OPG to pay a fixed rate and to receive a variable rate on a total notional volume of 906,000 MWh for a term of 5 years, commencing on the date of Open Access.

Hydro One has several service level agreements with the other successor corporations, primarily OPG. These services include field and engineering, logistics, corporate, telecommunication and information technology services. Revenues related to the provision of services to the other successor corporations and operation, maintenance and administration costs related to the purchase of services from the other successor corporations are summarized in the following table:

Year ended December 31 (Canadian dollars in millions)	2001	2000	1999
Revenues			
Transmission	16	61	58
Distribution	7	3	6
	23	64	64
Operation, Maintenance and Administration			
Transmission	3	15	32
Distribution	1	3	15
	4	18	47

As at December 31, 2001, long-term debt in the amount of $2,972 million (2000 - $3,446 million) was due to OEFC. Financing charges for 2001, include interest expense on this debt in the amount of $288 million (2000 - $330 million; 1999 - $411 million). Allocated debt for the period prior to April 1, 1999 included bonds and notes payable to the Province as well as to unrelated parties. In respect of the allocated debt, Hydro One paid a debt guarantee fee to the Province. Since April 1, 1999, the Province has not guaranteed Hydro One's debt, and accordingly, the provincial debt guarantee fee is no longer incurred.

Provision for payments in lieu of corporate taxes were paid or payable to OEFC and dividends were paid or payable to the Province (see Note 2).

The amounts due to and from related parties a s a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in millions)	2001	2000
Accounts receivable	119	144
Accounts payable and accrued charges	(167)	(157)

Included in accounts payable and accrued charges are amounts owing to OPG in respect of power purchases for $167 million (2000 - $81 million).

19. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the consolidated statements of cash flows, balance sheet item "bank indebtedness" has been netted against "cash and cash equivalents."

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	2001	2000	1999
Accounts receivable (increase) decrease	(149)	25	(16)
Materials and supplies decrease (increase)	9	16	(16)
Accounts payable and accrued charges increase (decrease)	334	(46)	128
Accrued interest (decrease) increase	(7)	(8)	78
Long-term accounts payable and accrued charges increase (decrease)	3	6	(72)
Employee future benefits other than pension increase	1	13	36
Other	(3)	17	(20)
	188	23	118
Supplementary information:			
Interest paid	383	384	324
Payments in lieu of corporate income taxes	241	213	169

20. CONTINGENCIES

Legal proceedings

As a result of Hydro One's acquisition of certain transmission, distribution and energy services assets, liabilities, rights and obligations of Ontario Hydro, Hydro One has succeeded Ontario Hydro as a party in a number of legal proceedings. In 1995, Torcom Communications Inc. (Torcom) named Ontario Hydro as one of several defendants in a suit seeking damages of $150 million, as well as specific performance of certain agreements and interim injunctive relief. Torcom had sought to purchase certain telecommunication devices belonging to a bankrupt company from the court-appointed receiver. The devices had been installed on Ontario Hydro property under license to the original owner. Torcom claims that it reached an agreement with Ontario Hydro for the continued placement of the devices on Ontario Hydro property. Torcom alleges Ontario Hydro breached this contract and interfered with its efforts to purchase the devices from the receiver. There has been little activity on the case since 1995, when Ontario Hydro served a demand to particularize the allegations against it. Ontario Hydro did not receive a reply to its demand for particulars and has not yet served a statement of defense. Hydro One believes that there are strong defenses to the plaintiff's claims against Ontario Hydro and that it is unlikely that the outcome of the litigation will have a material adverse effect on its business, results of operations, financial position or prospects.

Hydro One is one of many defendants in a suit in the Superior Court of Justice commenced on October 18, 1995, asserting aboriginal title to certain land within the City of Sarnia. The plaintiff, The Chippewas of Sarnia Band, alleges that the land was not properly surrendered before a Crown Patent was issued in 1853 and therefore subsequent owners who took possession under the Crown Patent do not possess valid title. Hydro One maintains transmission line facilities on portions of the disputed land. Hydro One cannot estimate the costs that might result from an adverse decision. On April 30, 1999, summary judgement was granted, dismissing the action against Ontario Hydro and certain defendants. On May 27, 1999, the plaintiff appealed the summary judgement order to the Court of Appeal for Ontario. Further, several defendants have also appealed the summary judgement order and others, including Hydro One, have filed cross-appeals. The appeals were argued in June 2000. The Court of Appeal decision rendered December 21, 2000 dismissed the plaintiffs' appeal and granted the appeals of the other parties. The plaintiff filed a motion for leave to appeal to the Supreme Court of Canada. On November 8, 2001, the Supreme Court of Canada dismissed the leave to appeal application with costs, thereby affirming the Court of Appeal decision. On December 18, 2001, the plaintiff brought a motion for reconsideration of the leave to appeal decision and seeks a reversal of the denial of the leave application or an order for an oral hearing of the leave to appeal application. Such orders are rare and made only in exceptional circumstances. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on its business, results of operations, financial position or prospects.

On March 29, 1999, the Whitesand First Nation Band commenced an action in the Ontario Court (General Division), naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG and the Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The reason for the second claim is the procedural defence of the Province that proper notice of the first claim was not given under the *Proceedings Against the Crown Act* (Ontario). These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The Whitesand Band alleges that since at least the first half of the twentieth century, Ontario Hydro has erected dams, generating stations and other facilities within or affecting the band's traditional lands and that those facilities have caused damage to band members and the lands, including substantial flooding and erosion. The Whitesand Band also claims treaty rights to a share of the profits arising from the activities of these Ontario Hydro facilities, an entitlement to increases in annuity payments established by treaty and compensation for costs incurred in the course of prior negotiations of band grievances with Ontario Hydro. The Whitesand Band asserts multiple causes of action, including trespass, breach of fiduciary duty, nuisance and negligence. To date, Hydro One has not filed a defence. The Company has requested particulars of the claims as have the other defendants. Following receipt, Hydro One will be filing a defence. The claims relating to activities of Ontario Hydro (i.e., flooding) are the matters for which OPG would have responsibility pursuant to Transfer Orders under the *Electricity Act, 1998*. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on its business, results of operations, financial position or prospects.

Transfer of Assets

On April 1, 1999, in connection with the acquisition of its operations, Hydro One acquired and assumed assets, liabilities, rights and obligations of Ontario Hydro's electricity transmission, distribution and energy services businesses, except for certain transmission, distribution and other assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Transfer of title to these assets did not occur because authorizations originally granted by the Minister of Indian Affairs and Northern Development (Canada) for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant Indian bands or bodies or, in several cases, because the authorizations had either expired or had never been properly issued. Hydro One manages these assets, which are currently owned by OEFC.

Hydro One has commenced negotiations with the relevant Indian bands and bodies to obtain the authorizations and consents necessary to complete the transfer of these transmission, distribution and other assets. Hydro One cannot predict the aggregate amount that it may have to pay to obtain the required authorizations and consents. Hydro One expects to pay more than $850,000 per year, which was the amount previously paid to these Indian bands and bodies by Ontario Hydro and which was the total amount of allowed costs in the transitional rate orders. If after taking all reasonable steps, Hydro One cannot otherwise obtain the authorizations and consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time. Alternatively, Hydro One may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial, or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. In such cases, Hydro One would apply to the OEB to recover these costs in future rate orders.

21. OPERATING LEASE COMMITMENTS

The future minimum lease payments under operating leases for each of the five years subsequent to December 31, 2001 and in total thereafter are as follows: 2002 - $19 million; 2003 - $15 million; 2004 - $13 million; 2005 - $7 million; 2006 - $6 million; and thereafter - $6 million.

22. SEGMENT REPORTING

Hydro One has three reportable segments:

I. The transmission business, which comprises the core business of providing transportation and connection services and is responsible for transmitting electricity throughout the Ontario electricity grid;
II. The distribution business, which comprises the core business of delivering and selling electricity to customers; and
III. An "other" segment primarily consisting of energy services, telecom, head office and the results of Ontario Hydro International.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2). Segment information on the above basis is as follows:

Year ended December 31 (Canadian dollars in millions)	2001	2000	1999
Transmission			
Revenues	1,259	1,260	1,237
Operation, maintenance and administration	354	433	423
Depreciation and amortization	219	198	179
Segment profit before transitional cost adjustment, Provincial debt guarantee fee and financing charges	686	629	635
Distribution			
Revenues	2,158	1,703	1,793
Operation, maintenance and administration	391	388	382
Purchased power	1,265	857	900
Depreciation and amortization	163	143	152
Segment profit before transitional cost adjustment, Provincial debt guarantee fee and financing charges	339	315	359
Other			
Revenues	49	32	95
Operation, maintenance and administration	79	42	58
Purchased power	2	2	39
Depreciation and amortization	2	7	11
Segment (loss) before transitional cost adjustment, Provincial debt guarantee fee and financing charges	(34)	(19)	(13)
Capital expenditures			
Transmission	274	280	327
Distribution	715	175	186
Other	45	14	16
	1,034	469	529

December 31 (Canadian dollars in millions)	2001	2000
Total assets		
Transmission	6,693	6,477
Distribution	4,416	3,434
Other	122	86
	11,231	9,997

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada, except for the operations of Ontario Hydro International prior to 2000 (see Note 8).

23. SUBSEQUENT EVENT

Effective March 1, 2002, the Company will transfer to Cap Gemini Ernst & Young approximately 900 employees currently involved in Hydro One information technology and various other business processes. This initiative enables Hydro One to focus on its core transmission and distribution businesses and turn to competitive external service providers for other services.

Cap Gemini Ernst & Young will offer services to Hydro One through a new entity, Inergi LP (Inergi). In connection with this initiative, Hydro One will receive from Inergi a range of services including information technology, customer care, supply chain and certain human resources and finance services for a 10-year period. The initial service level price initially ranges between $90 million and $130 million per year, subject to external benchmarking every three years to ensure Hydro One is receiving a defined competitive and continuously improved price.

24. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2001 Consolidated Financial Statements.

25. RECONCILIATION TO U.S. GAAP

The Consolidated Financial Statements of Hydro One have been prepared in accordance with Canadian GAAP, which conforms in most respects to U.S. GAAP. Under both Canadian GAAP and U.S. GAAP, certain of the Company's accounting policies differ from those that would be followed by enterprises operating in a non-rate-regulated environment.

The material differences between Canadian GAAP, as used in the preparation of these Consolidated Financial Statements, and U.S. GAAP, are summarized below.

Consolidated Statements of Operations

Year ended December 31 (Canadian dollars in millions)	**2001**	**2000**	**1999**
Net income	374	378	375
Adjustments increase (decrease):			
Employee future benefits other than pension (a)	(2)	(6)	8
Staff reduction charges (b)	-	(60)	45
Corporate write-offs (c)	(2)	(2)	(24)
Net income and comprehensive income (U.S. GAAP)	370	310	404
Retained earnings, opening	200	292	-
Dividends	(258)	(402)	-
Excess of assets over liabilities, March 31, 1999	-	-	(2,870)
Excess of assets over liabilities, opening (U.S. GAAP)	-	-	2,758
Excess of assets over liabilities, closing (U.S. GAAP)	-	-	-
Retained earnings, December 31 (U.S. GAAP)	312	200	292

Consolidated Balance Sheets

December 31 (Canadian dollars in millions)	2001	2000
Assets: increase (decrease)		
Fixed assets in service (a),(c)	19	24
Regulatory assets – environmental (d)	-	190
Regulatory assets – deferred tax (e)	118	97
Liabilities: (increase) decrease		
Accounts payable and accrued charges (c)	8	8
Employee future benefits other than pension (a)	(4)	(11)
Environment liabilities (d)	-	(190)
Deferred tax liability (e)	(118)	(97)
	23	21

(a) Employee Future Benefits Other than Pension

Under U.S. GAAP, actuarial gains or losses are immediately recognized in results of operations. Under Canadian GAAP, such amounts can be deferred and amortized over the average remaining service period of active employees. Under U.S. GAAP, liabilities for other post employment benefits (OPEB) at December 31, 2001 and 2001 OPEB cost would have been $4 million higher due to the immediate recognition of the actuarial loss (2000 - $11 million higher; 1999 - $13 million lower due to a gain) resulting from a change in the current market settlement rate at December 31. Of this, $2 million would have been charged to the results of operations (2000 - $6 million charged; 1999 - $8 million credited) and $2 million would have been capitalized (2000 - $5 million capitalized; 1999 - $5 million credited to) as part of the cost of fixed assets.

(b) Staff Reduction Charges

Under Canadian GAAP prior to January 1, 2000, costs relating to staff reduction programs were recognized at the time management approved such reductions and the costs could be reasonably estimated. Under U.S. GAAP, the cost of staff reduction programs can not be recognized unless the program meets specific additional criteria and, for a voluntary retirement programs, if the employees actually accept an offer of early retirement.

Ontario Hydro provisions for staff reduction costs in the amount of $15 million were allocated to Hydro One on April 1, 1999, against which actual staff reduction expenditures of $1 million were incurred during 1999. Hydro One reversed the remaining provision of $14 million as a credit to results of operations in 1999. Under U.S. GAAP, the original provision and its subsequent reversal would not have been recorded and the actual expenditures incurred would have been charged to the results of operations during 1998 and 1999.

During 1999, Hydro One recorded a new provision for voluntary staff reduction costs in the amount of $60 million and in 2000, Hydro One reversed $5 million of this provision as a credit to the results of operations. Under U.S. GAAP, the original provision would not have been recorded in 1999. Instead, a provision for $55 million would have been recorded in 2000 as employees actually accepted the early retirement offer. Therefore, U.S. GAAP income would have been lower in 2000 by $60 million due to a combination of the $55 million staff reduction provision and the absence of the $5 million credit resulting from the 2000 reversal of a portion of the provision recognized under Canadian GAAP in 1999.

(c) Corporate Write-offs

In 1997, Ontario Hydro recorded a $33 million expense related to the future disposal of certain field operation centres, consisting of a $25 million write-down of fixed assets and a $8 million provision for non-discretionary post-occupancy costs. Under U.S. GAAP, the fixed assets would have remained on the balance sheet as assets held for future use and would have continued to be depreciated at $2 million per year. In addition, the provision for non-discretionary post-occupancy costs would not have been recorded.

In 1993, Ontario Hydro recorded a real estate provision in the amount of $22 million, which was reversed by Hydro One as a credit to results of operations in 1999. Under U.S. GAAP, the provision and its subsequent reversal would not have been recorded.

(d) Environmental Costs

As a result of the January 1, 2001 change in accounting policy, Hydro One was in compliance with U.S. GAAP throughout 2001. However, prior to January 1, 2001, it was Hydro One's policy to expense the costs to settle past environmental damage as those costs were incurred. That policy was also the basis on which the Company's transmission and distribution rates were set. For U.S. GAAP purposes, a discounted liability and regulatory asset of $190 million would have existed as at December 31, 2000, equal to the opening January 1, 2001 balances under Canadian GAAP (see Notes 12 and 16).

(e) Deferred Income Taxes

For a rate regulated enterprise, U.S. GAAP requires the reporting and display of deferred income tax liabilities and assets on the balance sheet. To the extent that the deferred income taxes are expected to be included in the approved rates charged to customers in the future, the Company would record a regulatory asset. The amount of deferred taxes reported for U.S. GAAP, determined on the basis of enacted income tax rates, is based on information included in Note 10.

(f) Acquisitions of Municipal Electricity Utilities

As set forth in Note 4 to the Consolidated Financial Statements, Hydro One acquired a number of municipal electricity utilities during the year. Under U.S. GAAP, the Company is required to disclose, as supplemental information, the results of operations as though the acquisitions had occurred at the beginning of the preceding period. The unaudited pro forma results of operations of the Company for the years ended December 31, 2001 and 2000, assuming that the acquisitions of municipal electricity utilities had been consummated as of January 1, 2000, are as follows:

Year ended December 31 (Canadian dollars in millions)	**2001**	**2000**
Revenues	3,720	3,496
Net income	356	347

(g) Proportionate Consolidation of Joint Ventures

Under Canadian GAAP, Hydro One accounted for its indirect investment in Ontario Quinta using the proportionate consolidation method. Under U.S. GAAP, Hydro One's indirect investment in Ontario Quinta would have been accounted for using the equity method. However, U.S. securities regulations allow Hydro One to omit from the U.S. GAAP reconciliation the differences resulting from the use of the proportionate consolidation method.

The following table summarizes the effects on the results of operations and financial position of using proportionate consolidation to account for the Ontario Quinta investment for the period prior to the sale. The effect on net income was equal to that which would have been obtained under the equity method.

Year ended December 31 (Canadian dollars in millions)	2001	2000	1999
Revenues	-	-	69
Operation, maintenance and administration	-	-	24
Purchased power	-	-	37
Depreciation and amortization	-	-	4
Financing charges	-	-	-
Net income	-	-	4

(h) Transitional Cost Adjustment

As set forth in Note 7 to the Consolidated Financial Statements, the Company recorded a transitional cost adjustment in the first three months of 1999. Under U.S. GAAP, the transitional cost adjustment would not be recognized as a specific cost line item in the first three months of 1999. Instead, under U.S. GAAP, the transitional cost adjustment would have been netted against revenue.

(i) Statement of Cash Flows

Under U.S. GAAP, bank indebtedness is not included in deriving cash and cash equivalents for purposes of the statement of cash flows. Bank indebtedness is classified as a financing activity.

(j) Derivative Instruments and Hedging Activities

The Company's interest rate and electricity swap contracts (see Note 15) are derivative financial instruments as defined in Statement of Financial Accounting Standard (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*. The interest rate swaps would be accounted for under SFAS No. 133 as cash flow hedges of forecast borrowings. To the extent the swap contracts are effective hedges, changes in fair value would be reported in Other Comprehensive Income (OCI) and transferred to results of operations when interest on the hedged borrowings is recognized. In addition, premiums or discounts recorded when Hydro One terminates hedges related to future borrowing requirements, would be reported in OCI and transferred to results of operations when interest on the hedged borrowings is recognized. The fair value of the interest rate swaps as at December 31, 2001 was nil and the premium received of $2.2 million was immaterial and, therefore, there would be no material effect on results of operations or financial position as a result of applying SFAS No. 133.

Under SFAS No.133, the electricity swaps would be reported at fair value in the consolidated balance sheet. They would be accounted for as cash flow hedges of forecast spot purchases of electricity required to satisfy the Company's retail sales contracts. To the extent the swap contracts are effective hedges, changes in fair value would be reported in OCI and transferred to results of operations when the hedged purchases are recognized. The fair value of the electricity swaps as at December 31, 2001 was immaterial and, therefore, there would be no material effect on results of operations or financial position as a result of applying SFAS No. 133.

(k) Future Accounting Pronouncements

On June 30, 2001, the Financial Accounting Standard Board (FASB) issued SFAS 141, *Business Combinations*, which eliminates the pooling-of-interest method of accounting for business combinations and requires the use of the purchase method. In addition, it requires the reassessment of intangible assets to determine if they are appropriately classified either separately or within goodwill. SFAS 141 is effective for business combinations initiated after June 30, 2001. On July 1, 2001, Hydro One adopted CICA Section 1580, *Business Combinations*, which is consistent with SFAS 141. There is no material impact on the Company's results of operations and financial position as a result of adopting these standards.

On June 30, 2001, the FASB issued SFAS 142, *Goodwill and Other Intangible Assets*, which eliminates the amortization of goodwill and other acquired intangible assets with indefinite economic useful lives. SFAS 142 requires an annual impairment test of goodwill and other intangible assets that are not subject to amortization. SFAS 142 is effective for fiscal years beginning after December 15, 2001. Hydro One will adopt CICA Section 3062, *Goodwill and Other Intangible Assets*, on January 1, 2002, which is consistent with SFAS 142. Application of the non-amortization provisions is not expected to result in a material increase in net income. During 2002, the Company will perform the first of the required impairment tests as of January 1, 2002, and does not expect that the results from these tests will result in any material impact on the results of operations and financial position of the Company.

On June 30, 2001, the FASB approved SFAS 143, *Accounting for Asset Retirement Obligation*, for obligations associated with the retirement of long-lived assets. SFAS 143 requires a liability to be recognized in the financial statements for retirement obligations meeting specific criteria. Measurement of the initial obligation is to approximate fair value with an equivalent amount recorded as an increase in the value of the capitalized asset. The asset will be depreciated in accordance with normal depreciation policy and the liability will be increased for interest accretion, with a charge to the statement of operations, until the obligation is settled. Regulated enterprises may recognize a regulated asset or liability for differences in timing of recognition of costs for accounting and rate making purposes. SFAS 143 is effective for fiscal years beginning after June 15, 2002. The potential impact of adopting SFAS 143 is not yet determinable, but may be material.

On October 3, 2001, the FASB approved SFAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which addresses financial accounting and reporting for the impairment and disposal of long-lived assets. While SFAS 144 supersedes SFAS 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*, it retains many of the fundamental provisions of that Statement. SFAS 144 also supersedes the accounting and reporting provisions of Accounting Principles Board Opinion 30, *Reporting the Results of Operations - Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occuring Events and Transactions*, for the disposal of a segment of a business. However, it retains the requirement in Opinion 30 to report separately discontinued operations and extends that reporting to a component of an entity that either has been disposed or is classified as held for sale. SFAS 144 is effective for fiscal years beginning after beginning after December 15, 2001. The impact of adopting SFAS 144 is not expected to be material.

HYDRO ONE INC.
FIVE-YEAR[1] SUMMARY OF FINANCIAL AND OPERATING STATISTICS

Year ended December 31 (Canadian dollars in millions)	2001	2000	1999	1998	1997
Statement of operations data					
Revenues	3,466	2,995	3,125	3,048	3,099
Costs					
Operation, maintenance and administration[2]	824	863	863	723	706
Purchased power	1,267	859	939	1,165	1,250
Depreciation and amortization	384	348	342	300	302
Transitional cost adjustment[3]	-	-	55	-	-
Provincial debt guarantee fee[4]	-	-	8	31	32
Deferred pension asset[5]	-	-	-	(204)	-
	2,475	2,070	2,207	2,015	2,290
Other income					
Gain on sale of investment[6]	-	-	32	-	-
Income before financing charges and provision for payments in lieu of corporate income taxes	991	925	950	1,033	809
Financing charges	350	340	381	559	584
Income before provision for payments in lieu of corporate income taxes	641	585	569	474	225
Provision for payments in lieu of corporate income taxes[7]	267	207	194	-	-
Net income	374	378	375	474	225
Basic and fully diluted earnings per common share *(Canadian dollars)*	3.562	3.182	-	-	-

1 The results of operations and financial positions prior to April 1, 1999 may have been different if Hydro One had been a stand-alone corporation with its own management and capital structure, rather than a business unit of Ontario Hydro.

2 Operation, maintenance and administration for 1999 includes a net charge of $24 million for a staff reduction program and the reversal of certain provisions. In 1997, Ontario Hydro's Board of Directors approved a charge in the amount of $79 million related to field operation centres, certain cost of programs, the consolidation of facilities and planned employee reductions.

3 The transitional cost adjustment was a one-time charge related to the first three months of 1999 (see Note 7).

4 The provincial debt guarantee fee was an annual fee equal to one-half of one percent (0.5%) of the total debt guaranteed by the Province outstanding as of the preceding December 31. This fee was eliminated effective April 1, 1999 (see Note 18).

5 The provisions of the *Electricity Act, 1998*, allow Hydro One to reduce employer contributions to the pension plan to the extent permitted under the *Pension Benefits Act* (Ontario), effective April 1, 1998. As a result, the deferred pension asset was increased by $204 million with a corresponding credit to 1998 operations.

6 The gain on sale of investment relates to the sale of the Company's 25% equity interest in Ontario Quinta (see Note 8).

7 As of April 1, 1999, Hydro One is required to make payments in lieu of corporate taxes (see Notes 2 and 10).

HYDRO ONE INC.
FIVE-YEAR[1] SUMMARY OF FINANCIAL AND OPERATING STATISTICS (continued)

Year ended December 31 (Canadian dollars in millions)	2001	2000	1999	1998	1997
Financial position data					
Total assets	11,231	9,997	10,090	9,435	9,059
Other financial data					
EBITDA[8]	1,375	1,273	1,292	1,333	1,111
Capital expenditures:					
Transmission	274	280	327	171	176
Distribution	715	175	186	188	126
Other	45	14	16	35	22
Ratios					
Net asset coverage on long-term debt[9]	1.88	1.90	1.83	1.43	1.37
Earnings coverage ratio[10]	2.53	2.37	2.19	1.82	1.37
U.S. GAAP (Canadian dollars)					
Net income and comprehensive income	370	310	404	446	272
Retained earnings	312	200	292	-	-
Earnings coverage ratio[10]	2.52	2.20	2.26	1.77	1.45
Operating statistics					
Transmission:					
Units transmitted (TWh)	146.9	146.9	144.1	143.0	144.8
System peak demand (MW)	25,269	23,428	23,435	22,443	22,197
Total transmission lines (kilometres)	28,387	28,490	28,889	29,066	29,080
Distribution:					
Units distributed (TWh)	21.3	17.6	18.1	18.3	18.8
Total distribution lines (kilometres)	122,399	113,880	113,400	116,947	119,182
Customers[11]	1,193,089	957,474	933,990	977,835	973,439
Total employees	4,815	4,468	5,632	5,221	5,222

8 EBITDA represents income before financing charges, provision for payments in lieu of corporate income taxes, depreciation and amortization and does not include financing income.

9 Net asset coverage on long-term debt is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt including current portion.

10 The earnings coverage ratio has been calculated as the sum of net income, gross interest expensed (which excludes capitalized interest) and provision for payments in lieu of corporate income taxes divided by the sum of gross interest plus cumulative preferred dividends. On March 31, 2000, preferred dividends of $13 million were declared in respect of the nine months ended December 31, 1999. As a result, the earnings coverage ratio would have been 2.30 in 2000 (U.S. GAAP – 2.13) and 2.26 in 1999 (U.S. GAAP – 2.33) on the basis of dividends declared.

11 As of April 1, 1999, Hydro One served approximately 934,000 retail customers. The reduction over years prior to 1999 was a result of statutory annexations under the *Power Corporation Act* of a small portion of facilities by several municipal electricity utilities. Subsequent increases reflect the acquisitions of municipal electricity utilities.

HYDRO ONE INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion in conjunction with our Consolidated Financial Statements for the three-year period ended December 31, 2001. This discussion contains forward-looking statements that are subject to risks, uncertainties and assumptions. Such information represents our current views based on information as at the date of this report. We do not intend to update this information and disclaim any legal obligation to the contrary.

We prepare our financial statements in Canadian dollars and in accordance with accounting principles generally accepted in Canada, (Canadian GAAP), which differs in some respects from accounting principles generally accepted in the United States (U.S. GAAP). See Note 25 to the Consolidated Financial Statements for the three-year period ended December 31, 2001. The following discussion is based upon our Consolidated Financial Statements prepared in accordance with Canadian GAAP, except as otherwise indicated.

Overview

Our Businesses

We own and operate the second largest transmission system in North America and the largest distribution system in Ontario, based on assets as at December 31, 2001. Our company was formed as part of the reorganization of Ontario Hydro and acquired the transmission, distribution and energy services businesses of Ontario Hydro as of April 1, 1999.

In 2001, our transmission business generated approximately 36% of our total revenues and approximately 69% of our profit before financing charges and provision for payments in lieu of corporate income taxes, while our distribution business accounted for approximately 62% of our total revenues and approximately 34% of our profit before financing charges and provision for payments in lieu of corporate income taxes. The contribution to revenues of our distribution business is significantly higher than the contribution to the revenues of our transmission business because the cost of power is included in the revenues of our distribution business.

Our businesses are in three segments: transmission; distribution; and other businesses.

Our transmission business, which represented approximately $6.7 billion of our assets as at December 31, 2001, transmits electricity through an approximately 28,400 circuit-kilometre high-voltage transmission network. We transmit electricity from generators to local distribution companies, including our own distribution network, and industrial customers with a direct connection to our transmission system. We own and operate this high-voltage transmission system as well as 26 facilities that inter-connect our transmission system with systems in neighbouring provinces and states.

Our distribution business, which represented approximately $4.4 billion of our assets as at December 31, 2001, distributes electricity through our approximately 122,000 circuit-kilometre low-voltage distribution system to approximately 1.2 million rural and urban customers, and local distribution companies that are not directly connected to our high-voltage transmission system. Our distribution service territory includes all of Ontario, excluding the service territories of the 97 local distribution companies that we do not own. Since April 1999, we have acquired 88 local distribution companies that we now operate as part of our distribution business. We also operate generation and distribution systems in 19 remote communities across northern Ontario that are not connected to Ontario's electricity grid.

Our other businesses, which represented approximately $122 million of our assets as at December 31, 2001, involve the marketing of our fibre-optic capacity to telecommunications carriers and commercial customers, and the retail sale of energy and related services.

Since the date of incorporation, all of the outstanding shares of our company have been owned by the Province of Ontario (the Province). On March 28, 2002, we filed a preliminary prospectus in Canada and a registration statement on Form F-1 in the United States in contemplation of the sale of our outstanding common shares by the Province (the Offering).

On April 19, 2002, the Ontario Superior Court ruled that the *Electricity Act, 1998* restricted the Province's right to sell the common shares of Hydro One that it owns. On April 25, 2002, the Province announced that it will appeal the court ruling and that it intends to develop proposed legislation in respect of the privatization of Hydro One.

Revenues and Costs

We earn transmission revenues based on the peak demand for electricity capacity across our high-voltage network, and we earn distribution revenues by delivering power to our distribution customers. The rates that we charge are established under rate orders issued by the Ontario Energy Board for these regulated businesses. Distribution revenues have been based on a "bundled" customer charge for the cost of power, transmission and distribution of electricity as well as related services to customers in our service territory.

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. In addition, these costs include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Purchased power costs incurred in our distribution business primarily represent the costs of electricity delivered to customers within our distribution service area.

Financing charges primarily consist of interest expense associated with our debt.

Since April 1, 1999, we have been making payments in lieu of corporate income taxes to Ontario Electricity Financial Corporation in accordance with the *Electricity Act, 1998* on the same basis as if we were subject to federal and provincial corporate taxes. We provide for payments in lieu of corporate income taxes relating to our regulated businesses using the taxes payable method as directed by the Ontario Energy Board. As a result of the Offering, we will instead pay corporate income taxes to federal and provincial tax authorities.

Regulation of Our Businesses

Our industry has undergone a significant restructuring initiated by the Province. Under the *Electricity Act, 1998*, as of April 1, 1999, the businesses of Ontario Hydro were reorganized into five separate corporations, including our company as the successor corporation to Ontario Hydro's electricity transmission, distribution and energy services businesses. We expect the restructuring to result in Ontario's wholesale and retail electricity markets becoming open to competition, commonly referred to as Open Access, on May 1, 2002.

During the transition to Open Access, electricity consumers pay bundled rates, consisting of an aggregate charge for the generation, transmission and distribution of electricity that they use as well as other related charges. The aggregate amount of these bundled rates is allocated among generators, transmitters and distributors. The amounts owing to the five successor corporations to Ontario Hydro are allocated under the terms of a revenue allocation agreement entered into by them. Upon Open Access, electricity consumers will pay unbundled rates for the generation, transmission and distribution of the electricity used by them and other related charges.

Prior to Open Access, revenues are allocated to our transmission and distribution businesses under rate orders based on a revenue requirement that provides for an annual rate of return of 9.88% on the common equity deemed to be allocated to our transmission and distribution businesses. The rate orders are premised upon a deemed capital structure of 60% debt, 4% preferred equity and 36% common equity for each of our regulated businesses. Any divergence in our actual capital structure affects the actual rate of return on the average common equity and the overall financial performance of these regulated businesses. The rate orders do not prescribe a capital structure for our company on a consolidated basis or for any of our non-regulated businesses. Currently, each of our regulated businesses has an actual capital structure which corresponds to the Ontario Energy Board deemed capital structure. In addition, the Ontario Energy Board could modify the annual rate of return and the deemed capital structure for our regulated businesses in the future, which could affect the financial performance of these regulated businesses and our company as a whole. If actual costs exceed allowed costs for any reason, the rate of return on our common equity and our resulting net income are likely to be adversely affected.

Upon Open Access, the Independent Electricity Market Operator will remit payments to us based on transmission rates approved by the Ontario Energy Board. The Ontario Energy Board has approved, on an interim basis, uniform transmission rates that will apply to all transmitters across Ontario following the commencement of Open Access. Our approved revenue requirement will remain unchanged as a result of these uniform rates and is designed to yield an approved rate of return of 9.88% on our deemed common equity. We are currently in the process of developing a performance based regulation rate proposal for our transmission business. The first step in such process will be consultation in 2002 with stakeholders, including customers, generators and other interested persons, on our proposal for a performance based regulatory framework for our transmission business.

In our distribution business, during 2001 the wholesale cost of power to us was increased on two occasions. Effective June 1, 2001, the Province passed a regulation that increased to all distribution companies, including ours, the wholesale cost of power supplied by Ontario Power Generation Inc. by 0.7 cents per kWh. The Ontario Energy Board approved the incorporation of this non-distribution-related increase into customers' bundled rates. The wholesale cost of power to our distribution business was further increased by 1.15 cents per kWh effective October 1, 2001 so that after such increase our cost of power was consistent with the rate paid by other large distributors. Following discussions with our shareholder, which requested us to mitigate the transition to these higher costs of electricity for our customers, we applied for lower distribution revenues than we had originally requested, with this mitigation to be partially phased out over a three-year period. The Ontario Energy Board issued an interim approval of the first phased increase, effective October 1, 2001; and the second phased increase, effective March 1, 2002. We have requested that the third phased increase be effective March 31, 2003. The Ontario Energy Board is expected to make a final determination with respect to the approval of these increases in mid-2002. As a result of the phasing-in of the partial recovery of the shortfall in our distribution revenues, we will not achieve our approved rate of return of 9.88% on deemed common equity of our distribution business in 2002 and 2003. In 2002, we will start the process to submit to the Ontario Energy Board a rate proposal based on a second generation performance based regulatory framework for our distribution business along with a proposal for our transmission business. We expect the Ontario Energy Board approved rates for 2004 to provide for a full market based rate of return.

We have also received interim approval of unbundled rates for the local distribution companies we acquired. We have separately filed rate applications for 2002 for these utilities with the Ontario Energy Board.

Upon Open Access, in addition to transmission and distribution revenues, we will receive revenues from end use consumers derived from our standard supply obligation and our competitive retail business. Our standard supply obligation refers to our obligation following the commencement of Open Access to sell electricity to every customer connected to our distribution system who has not selected an alternate electricity supplier. The Ontario Energy Board will regulate rates for our standard supply customers, but not for customers of our competitive retail business.

A condition of our distribution licence, as for all distributors, is fulfilment of preparations for Open Access, which is referred to as being "Market Ready". We have developed the systems, processes and communications required for Open Access and have participated in the successful market design tests sponsored by the Independent Electricity Market Operator. As a result, we believe that we are well-positioned to participate in the new marketplace and to meet our Market Ready obligations, while continuing to deliver electricity safely and reliably.

The restructuring of Ontario's electricity industry and the development of the regulatory framework will continue beyond the commencement of Open Access. Over the long-term, we believe that performance based regulation should benefit us and our customers by providing our company with an opportunity to enhance earnings while delivering rates to customers that reflect continuing efficiency improvements and maintain our current high levels of service.

Results of Operations

As used in this section, references to increases and decreases, whether in terms of amounts or percentages, in any year are made by comparison to the corresponding prior year.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Revenues

Transmission. Transmission revenues declined by $1 million to $1,259 million in 2001. Tariff revenues increased by $31 million, or 3%, in 2001 as a result of transmission load growth in accordance with the revenue allocation agreement. This increase was offset by a decline in non-energy related service revenues of $32 million as a result of substantial one-time revenues recorded in 2000 relating to contract work preparing other industry participants for Open Access.

Distribution. Distribution revenues increased by $455 million, or 27%, to $2,158 million in 2001. Revenues from the sale and delivery of electricity increased by $344 million, of which $268 million was attributable to the acquisitions of local distribution companies. In addition, revenues were higher as a result of the two rate increases related to the wholesale cost of power. The June 1, 2001 rate increase accounted for a $93 million rise in distribution revenues and the October 1, 2001 rate increase accounted for an additional $18 million.

Other. Other revenues increased by $17 million, or 53%, to $49 million in 2001. Energy services revenues increased by $10 million primarily due to increased sales of ancillary residential services. Revenues from our telecommunications business increased by $7 million, primarily from sales of dark fibre capacity to major carriers.

Operation, Maintenance and Administration Costs

Total operation, maintenance and administration costs declined by $39 million, or 5%, to $824 million in 2001, due to the factors discussed below.

Transmission. Transmission operation, maintenance and administration costs declined by $79 million, or 18%, to $354 million in 2001. Expenditures necessary to sustain our transmission system, including preventive and corrective maintenance on transformer stations, transmission lines and telecommunications equipment, declined by $17 million. In addition to achieving a full year of savings in 2001 as a result of the substantial completion of a staff reduction program in 2000, we embarked on a number of initiatives to enhance productivity, such as improving labour utilization. See "— Year Ended December 31, 2000 Compared to Year Ended December 31, 1999 — Staff Reduction Program and Other Provisions". Key initiatives to improve labour utilization include a hiring hall established with the Power Workers' Union to provide staffing flexibility and the use of temporary headquarters to reduce travelling time for our line and forestry crews. Expenditures to operate and support our transmission system declined by $24 million, primarily as a result of the staff reduction program. In addition, costs incurred to provide non-energy-related services declined by $38 million due to the substantial completion of work in 2000 for other industry participants in preparation for Open Access.

Distribution. Distribution operation, maintenance and administration costs increased by $3 million, or 1%, to $391 million in 2001. Costs incurred to sustain our distribution system, including our remote system, which are related primarily to customer trouble calls to restore power, vegetation management and line and station maintenance work, increased by $38 million. We also incurred an additional $13 million in one-time operation, maintenance and administration costs to integrate acquired local distribution companies. We achieved a reduction of $48 million in costs to operate and support our distribution system primarily from the staff reduction program as well as productivity initiatives similar to those of our transmission business.

Other. Other operation, maintenance and administration costs increased by $37 million to $79 million in 2001. This increase was primarily associated with the growth of our telecommunications and energy services businesses.

Purchased Power

Purchased power costs increased by $408 million, or 48%, to $1,267 million in 2001. The increase attributable to acquisitions and volume growth totalled $265 million, including $211 million attributable to acquisitions of local distribution companies. In addition, as discussed above under "— Regulation of our Business", the Province passed regulations effecting two increases in the wholesale cost of power during 2001. The June 1, 2001 and October 1, 2001 increases and a change in the pricing methodology of Ontario Power Generation Inc. resulted in higher purchased power costs totalling $143 million.

Depreciation and Amortization

Depreciation and amortization expense increased by $36 million, or 10%, to $384 million in 2001. Depreciation expense increased by $30 million primarily due to the acquisitions of local distribution companies as well as to our expanded capital expenditure program. Amortization expense increased by $6 million, of which $5 million was due to the amortization of the regulatory asset recorded effective January 1, 2001 for the recovery of costs required to remediate past environmental contamination and $1 million was due to the amortization of goodwill related to the acquisitions of local distribution companies.

Financing Charges

Financing charges increased by $10 million, or 3%, to $350 million in 2001. This increase principally reflects higher average levels of debt.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes increased by $60 million, or 29%, to $267 million in 2001. This increase reflects higher levels of income and lower available tax deductions, partially offset by a reduction in the statutory tax rate from 43.95% in 2000 to 41.74% in 2001. Lower tax deductions were primarily attributable to the absence in 2001 of tax deductions available in 2000 related to the staff reduction program and capital cost allowance deductions. Tax deductions related to the staff reduction program were primarily taken in 2000 when the related cash payments were made. As a result of the Offering, we will commence paying corporate income taxes to Canadian federal and provincial tax authorities.

Net Income

As a result of the above factors, net income declined by $4 million to $374 million in 2001. Net income after dividends on our preferred shares was $356 million in 2001, compared to $360 million in 2000 after adjusting for $13 million of 2000 preferred dividends paid in respect of 1999.

Excluding the impact of staff reductions, net income increased from $350 million in 2000 to $374 million in 2001. Excluding the impact of staff reductions, net income after dividends on our preferred shares increased from $332 million in 2000, after adjusting for $13 million of 2000 preferred dividends paid in respect of 1999, to $356 million in 2001.

Net income in 2001 for our regulated transmission and distribution businesses on a combined basis was in line with the annual regulated rate of return of 9.88% in 2001 provided for in our transitional rate orders.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Prior to 1999, transmission revenues were determined primarily based on an estimate of planned costs and a specified rate of return on assets. Distribution revenues were comprised of amounts received for the sale and delivery of electricity to customers and the rural rate assistance program, which is discussed below. Effective April 1, 1999, the Ontario Energy Board issued, and the Minister of Energy, Science and Technology approved, transitional rate orders that provide the transmission and distribution revenue requirements for 1999 and 2000.

Our company received revenues for the three months ended March 31, 1999 on the basis of the allowed costs under the transitional rate orders. Because we did not actually begin to incur these allowed costs until April 1, 1999, our costs for the first quarter of 1999 did not reflect the basis of our revenue requirement under the transitional rate orders. As a result, we recorded a transitional cost adjustment of $55 million, calculated as the difference between the costs allowed under the *Power Corporation Act*, which governed Ontario Hydro, and those allowed under the transitional rate orders to correct this mismatch. This adjustment will not recur because, after April 1, 1999, the costs incurred by our company are the higher costs assumed under these rate orders so that there will no longer be a mismatch between revenues and costs.

Additional allowed costs under the transitional rate orders consisted of payments in lieu of corporate taxes, as well as an amount for amortization relating to the recovery of other post-employment benefit costs. These additional costs were partially offset by reduced financing charges resulting from lower debt balances that reflected the new capital structure of our company and lower interest rates as well as the elimination of a debt guarantee fee levied by the Province.

The following discussion of our results of operations for 1999 is based on combined results for our twelve months ended December 31, 1999, which includes the three months ended March 31, 1999, the period prior to our acquisition of Ontario Hydro's transmission, distribution and energy services businesses. Our results of operations for this three month period reflect the specific identification of assets, liabilities, revenues and expenses relating to the businesses acquired by us as well as a notional allocation of specified financial statement accounts and items of Ontario Hydro to us and the other successor corporations of Ontario Hydro. See Note 2 to the Consolidated Financial Statements for the three-year period ended December 31, 2001.

Revenues

Transmission. Transmission revenues increased by $23 million, or 2%, to $1,260 million in 2000. Of this increase, $19 million was a result of the increase in the allowed rate of return to 9.88% in 2000 from 9.35% in 1999. The remaining increase in revenues was attributable to the increase in non-energy-related services provided to other industry participants in preparation for Open Access.

Distribution. Distribution revenues declined by $90 million, or 5%, to $1,703 million in 2000. Approximately $44 million of this decline was attributable to a reduction in allowed costs provided for under the distribution transitional rate order for 2000. In addition, revenues from the sale and delivery of electricity declined by $46 million, which includes a $41 million reduction related to a lower demand for electricity and a $16 million reduction related to the annexation of part of our service territory by a number of local distribution companies prior to April 1, 1999, partially offset by an $11 million reduction in line losses. The ability of municipalities to annex areas previously served by us ceased as of April 1, 1999.

Other. Other revenues declined by $63 million, or 66%, to $32 million in 2000. Other revenues for periods prior to 2000 were substantially derived from the activities of Ontario Hydro International Inc., a subsidiary that was wound-up effective as at January 1, 2002. As part of the process to wind-up its operations, the main operating asset, an investment in Ontario Quinta A.V.V., was sold on September 15, 1999. The reduction in revenues from Ontario Hydro International Inc. accounted for a reduction in other revenues of $72 million in 2000. Excluding the impact from Ontario Hydro International Inc., other revenues increased by $9 million in 2000 as a result of the launch of our telecommunications business and new energy services.

Operation, Maintenance and Administration Costs

Total operation, maintenance and administration costs amounted to $863 million in both 2000 and 1999.

Transmission. Transmission operation, maintenance and administration costs increased by $10 million, or 2%, to $433 million in 2000. Costs incurred to sustain our transmission system increased by $10 million. Higher costs for telecommunications and line work were partially offset by lower planning and engineering costs. Costs incurred to provide non-energy-related services increased by $4 million, consistent with the increase in the level of services provided. These increases were partially offset by a reduction of $4 million in centralized support costs, which was primarily attributable to the staff reduction program.

Distribution. Distribution operation, maintenance and administration costs increased by $6 million, or 2%, to $388 million in 2000. This increase primarily reflected incremental costs of $10 million incurred to integrate and support the acquisitions of local distribution companies. Costs incurred to sustain our distribution system were consistent with 1999. Lower costs for line maintenance and vegetation management were offset by higher costs to operate our remote system, primarily due to higher fuel prices. Operation, maintenance and administration costs incurred to operate and support the distribution system were also consistent with 1999 levels. Higher property taxes and payments in lieu of corporate taxes, as well as higher customer service operating costs were substantially offset by a reduction in centralized support costs. The reduction in centralized support costs was primarily related to the staff reduction program. These overall increases in distribution operation, maintenance and administration costs were partially offset by a reduction of $5 million in costs associated with non-energy-related services resulting from a change in the service mix.

Other. Other operation, maintenance and administration costs declined by $16 million, or 28%, to $42 million in 2000. The $31 million decrease attributable to Ontario Hydro International Inc. was partially offset by an increase of $15 million related to the establishment of the telecommunications and energy services businesses.

Staff Reduction Program and Other Provisions

In November 1999, we implemented a staff reduction program as part of our ongoing cost reduction program. We recorded a provision in 1999 in the amount of $60 million for this program. With approximately 1,400 employees accepting early retirement, the staff reduction program was substantially completed during 2000. Costs of $53 million were charged to the provision in 2000 and $2 million was charged in 2001. In 2000, $5 million of the provision was determined to be unnecessary and, accordingly, was reversed as a credit to the results of operations. In 1999, we also re-evaluated the need for some provisions previously recognized by Ontario Hydro and assumed by our company as of April 1, 1999. As a result, remaining provisions of $36 million associated with an involuntary staff reduction program and surplus real estate were reversed as a credit to the results of operations in 1999.

Purchased Power

Purchased power costs declined by $80 million, or 9%, to $859 million in 2000. Approximately $43 million of the reduction was due to the lower demand for electricity and the annexations by local distribution companies of areas that we previously served. The decline associated with the sale of our investment in Ontario Quinta A.V.V. amounted to $37 million.

Depreciation and Amortization

Depreciation and amortization expense increased by $6 million, or 2%, to $348 million in 2000. The increase in depreciation expense from our expanded capital expenditure program amounted to $16 million. This increase was partially offset by lower amortization expense of $10 million. A reduction of $20 million in amortization expense from a fully amortized regulatory asset in 1999 was partially offset by a $10 million increase in amortization of the regulatory asset associated with employee future benefit costs other than pension.

Transitional Cost Adjustment

We had a one-time transitional cost adjustment of $55 million in 1999 with respect to the three months ended March 31, 1999. This charge represented the difference between allowed costs specified in the transitional rate orders approved by the Ontario Energy Board and costs that were allowed under the *Power Corporation Act*.

Provincial Debt Guarantee Fee

The Province no longer guarantees our debt and, consequently, we did not incur a debt guarantee fee for any period subsequent to April 1, 1999. Prior to April 1, 1999, the Province guaranteed the debt of Ontario Hydro, for which Ontario Hydro paid an annual fee equal to one-half of one percent of the principal amount of such guaranteed debt.

Gain on Sale of Investment

On September 15, 1999, our subsidiary, Ontario Hydro International Inc., sold its 25% equity interest in Ontario Quinta A.V.V. We realized a gain of $32 million before payments in lieu of corporate income taxes on this sale in 1999.

Financing Charges

Financing charges declined by $41 million, or 11%, to $340 million in 2000. The decrease in 2000 was primarily due to a reduction in long-term debt servicing costs, with $28 million from lower average levels of debt and $10 million from lower average interest rates.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes increased by $13 million, or 7%, to $207 million in 2000. The provision for 2000 was based on our results of operations for a full-year as compared to nine months in 1999 consistent with the requirement to make these payments in lieu of corporate income taxes to Ontario Electricity Financial Corporation since April 1, 1999. On a comparative basis, the lower provision for 2000 reflected a lower level of income and an increase in deductions, primarily for the cash payments made under the staff reduction program that were recognized for accounting purposes in 1999.

Net Income

As a result of the above factors, net income increased by $3 million, or 1%, to $378 million in 2000. Excluding the effect of the gain on sale of our investment in Ontario Quinta A.V.V. and the impact of staff reductions, net income decreased from $377 million in 1999 to $350 million in 2000.

Net income in 2000 for our regulated transmission and distribution businesses was in line with the annual rate of return of 9.88% in 2000 provided for in our transitional rate orders. By contrast, the annual rate of return was 9.35% in 1999.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2000 through December 31, 2001. This information has been derived from our unaudited Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited Consolidated Financial Statements and include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period. You should not rely on them to predict our future performance.

	Quarter Ended							
	March 31, 2000	June 30, 2000	September 30, 2000	December 31, 2000	March 31, 2001	June 30, 2001	September 30, 2001	December 31, 2001
	(Canadian dollars in millions)							
Total revenue	828	679	715	773	816	722	880	1,048
Net income	126	118	101	33	134	114	103	23
Net income to common shareholder	121	114	96	29	129	110	98	19

Liquidity and Capital Resources

Liquidity and Capital Resource Requirements

Our principal liquidity and capital resource requirements consist of the following:

- capital expenditures to maintain, improve and expand our transmission and distribution assets;
- servicing and repayment of our debt;
- outsourcing arrangements;
- acquisitions and other investing activities;
- dividends; and
- recapitalization and other matters relating to the Offering.

Capital Expenditures

Our total capital expenditures amounted to $566 million in 2001, representing an increase of $120 million over spending levels of $446 million in 2000. Capital expenditures in 2000 were $83 million lower than 1999 levels of $529 million. These amounts exclude capital expenditures associated with acquisitions of local distribution companies.

Transmission. Capital expenditures for our transmission business were $274 million, $280 million and $327 million in 2001, 2000, and 1999, respectively. Capital expenditures on transmission stations, lines, equipment and telecommunications refurbishment were $184 million, $183 million and $193 million in 2001, 2000 and 1999, respectively. Increased spending on telecommunications facilities for transmission was partially offset by lower pole replacement work in 2001 compared to 2000. Lower pole replacement work and lower investments in transportation and work equipment were partially offset by increased load connection replacements and network refurbishment projects in 2000 compared to 1999. Capital expenditures incurred to expand our transmission system were $60 million and $64 million in 2001 and 2000, respectively, and were significantly lower than expenditures of $101 million in 1999. Capital expenditures in 1999 were higher than in 2001 and 2000 primarily as a result of the substantial completion of a number of construction and development projects in 1999. Capital expenditures supporting transmission operations declined marginally in 2001 to $30 million, compared to $33 million in each of 2000 and 1999.

Distribution. Capital expenditures for our distribution business, excluding expenditures associated with acquisitions of local distribution companies, were $247 million in 2001, compared with $152 million and $186 million in 2000 and 1999, respectively. Customer-demand-driven capital expenditures increased to $103 million in 2001, compared with $79 million in 2000 and $78 million in 1999. The expansion of our service territory through local distribution company acquisitions was a principal reason for this increase. Capital expenditures incurred to sustain our distribution asset base amounted to $94 million in 2001, compared with $34 million and $78 million in 2000 and 1999, respectively. In 2001, we enhanced our wood pole replacement program in response to an asset condition study. We also increased our spending levels on lines and stations in 2001, primarily in response to our expanded service territory and to higher storm damage. Capital expenditures supporting distribution operations increased to $50 million from $39 million in 2000 and $30 million in 1999. Projects for 2001 and 2000 have been focused on preparation of our systems and processes for Open Access.

Other. Capital expenditures for our other businesses amounted to $45 million in 2001 compared with $14 million in 2000, and $16 million in 1999. Increased expenditures in 2001 were made primarily in support of our emerging telecommunications business. In addition to lighting dark fibre in the Windsor, Fort Erie and Ottawa corridor, we began construction of a fibre-optic network between Buffalo, Ottawa and Montreal.

Future Capital Expenditures. Capital expenditures are budgeted at approximately $590 million in 2002. The budgets for our transmission and distribution businesses are $290 million and $260 million, respectively. Other capital expenditures are budgeted at $40 million and are primarily related to the expansion of our fibre-optic communication system between Buffalo, Ottawa and Montreal in support of our growing telecommunications business.

In addition to the ongoing sustainment requirements of the transmission and distribution systems, the 2002 budget includes a number of major projects. We plan to begin construction of an integrated operating centre to replace our eight territory operating centres in 2002 and complete the facility in 2004. Other projects include information technology enabling tools for our corporate functions and services staff and development opportunities such as an interconnection project with Hydro-Québec.

We have agreed to enter into a partnership with TransÉnergieUS, a subsidiary of Hydro-Québec, to build a high-voltage transmission line beneath Lake Erie, linking Ontario and Ohio or Pennsylvania, or both. On February 13, 2002, we and TransÉnergieUS received approval from the U.S. Federal Energy Regulatory Commission to proceed with a sale of the transmission rights for this line at negotiated rates by using an open season process to attract customers. Our share of the capital costs related to this project cannot currently be determined and would, in part, depend on the outcome of the sale of the transmission rights, but could be substantial in amount.

Servicing and Repayment of Our Debt

As at December 31, 2001, we had long-term debt outstanding of $4,522 million, including the current portion, with a weighted-average interest rate of 8.0%. Of this amount, $2,972 million is payable to Ontario Electricity Financial Corporation and $1,550 million is publicly held. Outstanding short-term promissory notes amounted to $410 million with a weighted-average interest rate of 2.16%.

The notes payable to Ontario Electricity Financial Corporation mature between 2002 and 2007, including approximately $443 million in 2002 and $651 million in 2003. We plan to refinance Ontario Electricity Financial Corporation debt maturing during 2002 and 2003 principally through our medium term note program. Our publicly held notes and debentures mature between 2005 and 2032.

Outsourcing Arrangement

We recently entered into an outsourcing services agreement with Inergi LP, an affiliate of Cap Gemini Ernst & Young Canada Inc. Under this agreement, Inergi LP will provide us with, among other things, customer service operations, supply management, pay operations, information technology, and finance and accounting services over a 10-year term. As part of this outsourcing arrangement, approximately 900 of our employees were transferred to Inergi LP. The initial fee payable to Inergi LP will be approximately $130 million in the first year of the contract declining to approximately $90 million in the tenth year of the agreement, net of inflation adjustments and subject to decreases based on external benchmarking analysis every three years. Because this outsourcing arrangement provides for a defined competitive and continuously improved price for the outsourced services, we believe that it will allow us to continue to reduce our cost base and improve our competitive position. As part of this agreement, we are still responsible for the capital expenditures associated with these services.

Acquisitions and Other Investing Activities

Cash used for investing activities increased by $475 million, or 88%, to $1,013 million in 2001 and by $297 million, or 123%, to $538 million in 2000, compared to the prior years. The increase in 2001 reflected our local distribution company acquisition program, through which we acquired 88 local distribution companies since April 1999. In 2001, we acquired 71 local distribution companies at a total cost of $475 million. In 2000, we acquired 16 local distribution companies at a total cost of $23 million and made deposits of $57 million with respect to acquisitions completed in 2001. Cash used for investing activities in 1999 also reflects the receipt of proceeds of $245 million from the sale of fixed assets and investments, primarily related to Ontario Quinta A.V.V.

We may pursue acquisitions of additional local distribution companies in 2002 or future years, although no specific material transactions are currently pending or under consideration. We also anticipate that, consistent with our long-term strategy, we will pursue, either alone or with partners, acquisitions of transmission and distribution businesses and assets in nearby market areas in North America. We believe that we will have access to sufficient sources of liquidity and capital resources, including through debt financing and/or issuances of new common shares by our company.

Dividends

We paid dividends to the Province on our outstanding preferred shares and common shares totalling $258 million in 2001 and $398 million in 2000. Dividends paid were substantially lower in 2001 because dividends of $171 million pertaining to 1999 were paid in 2000 in conjunction with the issuance of shares to the Province on March 31, 2000.

Our outstanding preferred shares are entitled to a total annual cumulative dividend of $18 million, payable on a quarterly basis.

The dividends on our common shares are declared at the discretion of our board of directors, and will be recommended by our management based on our results of operations, financial condition, cash requirements and other relevant factors, such as industry practice. In 2001, dividends on our common shares in the amount of $240 million were declared as compared with $371 million in 2000. Of these dividends declared during 2000, $158 million were declared in respect of the nine months ended December 31, 1999.

Recapitalization and Other Matters Relating to the Offering

Immediately prior to the completion of the Offering, the Province will subscribe for $290 million of our common shares at the initial public offering price, the proceeds of which will be used to fund our ongoing obligations. These additional common shares will also be offered for sale by the Province as part of the Offering. In connection with the Offering, we will redeem our outstanding preferred shares held by the Province for an aggregate redemption amount of $323 million, together with accrued dividends, within 120 days of the closing of the Offering. We plan to finance this redemption through an offering of a new series of preferred shares. Prior to that offering, we may finance this redemption through borrowings under our credit facility or other resources. As a result of the Offering, we will also be required to make a payment in lieu of corporate taxes of $440 million to Ontario Electricity Financial Corporation. We will not receive any proceeds from the Offering.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations as well as other major commercial commitments.

		Due by Year			
	Total	2002	2003/2004	2005/2006	After 2006
			(Canadian dollars in millions)		
Contractual obligations:					
Short-term notes payable	410	410	—	—	—
Long-term debt	4,522	443	1,333	1,096	1,650
Operating lease commitments	66	19	28	13	6
Energy purchase contracts (electricity and gas)	75	14	32	27	2
Inergi LP outsourcing agreement	1,050	108	230	212	500
Total contractual obligations	6,123	994	1,623	1,348	2,158

		Expiration Date by Year			
	Total	2002	2003/2004	2005/2006	After 2006
			(Canadian dollars in millions)		
Other commercial commitments:					
Letters of credit[1]	158	108	50	—	—
Guarantees[2]	80	—	—	80	—
Total other commercial commitments	238	108	50	80	—

(1) We currently have bank letters of credit of $108 million outstanding relating to retirement compensation agreements. In addition, upon Open Access, we will be required to provide prudential support to the Independent Electricity Market Operator, which requirement we intend to satisfy using a combination of bank letters of credit of $50 million and guarantees by Hydro One Inc. of our subsidiaries' obligations.

(2) Limited guarantees have been provided to counterparties of our subsidiary, Ontario Hydro Energy Inc.

Payments in respect of operating leases, energy purchase contracts (electricity and gas) and our new outsourcing agreement with Inergi LP are recorded under operation, maintenance and administration costs on our statement of operations or in our capital programs. The amounts in the above table under short-term notes payable and long-term debt are not charged to our statement of operations, but are reflected on our balance sheet and statement of cash flows. Interest associated with this debt is recorded under financing charges on our statement of operations or in our capital programs, but these financing charges are not reflected in the above table.

The above table does not include amounts payable as a result of the Offering as described under "— Recapitalization and Other Matters Relating to the Offering".

Sources of Liquidity and Capital Resources

Our primary sources of liquidity and capital resources are the following:

- funds generated from operations;
- debt capital markets borrowings; and
- bank financing.

Funds from operations, after the payment of dividends, will not be sufficient to fund our repayment of existing indebtedness and to meet our anticipated liquidity, maintenance and other capital resource requirements. As a result, we expect to incur significant amounts of debt. We do not expect that the covenants limiting the incurrence of indebtedness contained in our existing debt agreements will prevent us from incurring sufficient new indebtedness to meet our requirements for the foreseeable future.

Funds Generated from Operations

Net cash generated from operations was $914 million in 2001, compared with $725 million in 2000 and $840 million in 1999. The increase of $189 million in 2001 reflects significantly higher accounts payable and accrued charges, primarily from increases in the cost and volume of wholesale power, the operations of the acquired local distribution companies and higher provision for payments in lieu of corporate income taxes. The increase in accounts payable and accrued charges was partially offset by higher levels of accounts receivable from our electricity customers due to the increase in our customer base and the rate increases attributable to the wholesale cost of power.

The reduction in net cash generated from operations of $115 million in 2000 was due primarily to higher levels of working capital. Accounts payable and accrued liabilities declined due to cash payments made under the staff reduction program and the resulting reduction in payroll-related liabilities. Lower accounts payable and accrued liabilities were partially offset by a reduction in accounts receivable consistent with lower retail distribution revenue, a decline in inventory levels as a result of our rationalization program, and an increase in the accrual for employee future benefits other than pension.

Increases in regulatory assets and liabilities, environmental liabilities and the deferred pension asset reported on our balance sheets do not substantially affect our cash flow.

Financing Activities

Net cash generated from financing activities was $99 million in 2001 compared with cash used in financing activities of $679 million in 2000 and $170 million in 1999. Short-term liquidity is provided through funds from operations and our commercial paper program. We are authorized to issue up to $1 billion in commercial paper with a term to maturity of less than 365 days. As a back-stop to our commercial paper program, we have a revolving standby credit facility with a syndicate of banks of $750 million for a 364-day term and $250 million for a five-year term.

At December 31, 2001, we had $410 million of commercial paper outstanding, resulting in approximately $590 million of short-term funds available under the commercial paper program.

Long-term financing will be provided by our access to the debt markets including our medium term note program. The maximum authorized principal amount of medium term notes issuable under this program is $2.5 billion and is currently available until June 2003, at which time we plan to renew the program for an additional two years. We intend to use the medium term note program to meet most of our borrowing requirements for the foreseeable future. At December 31, 2001, we had $550 million principal amount of medium term notes outstanding, resulting in approximately $1.95 billion principal amount issuable under this program. We believe that we will be able to issue medium term notes on satisfactory terms, taking into account, among other factors, the investment grade ratings for our long-term senior, unsecured debt from major Canadian and

U.S. rating agencies. Standard & Poor's Rating Services recently downgraded our rating on long-term debt from "AA–" to "A+" and on short-term debt from "A-1+" to "A-1". Dominion Bond Rating Service Inc. confirmed its rating of "A" with a positive outlook. Moody's Investor Services Inc. confirmed its rating of "A1" with a negative outlook.

In 2001, we issued $550 million in debt under our medium term note program and had a net increase in short-term debt of $280 million under our commercial paper program. In 2001, we repaid $474 million of debt payable to Ontario Electricity Financial Corporation. In 2000, the proceeds of our $1 billion inaugural bond issue, as well as other cash resources, including a net increase of $130 million in commercial paper, were used to repay $1,399 million of debt payable to Ontario Electricity Financial Corporation. The financing activities for 1999 were primarily related to first quarter activities of Ontario Hydro.

Our revolving standby credit facility provides, in effect, that a sale by the Province of 50% or more of our voting shares and any resulting downgrading of our ratings for our long-term senior unsecured debt from Moody's below "A3" or Standard & Poor's below "A-" within 30 days following that sale will constitute an event of default under the facility. We do not expect the Offering to result in an event of default under this credit facility.

After completion of the Offering, we believe that primary offerings of new common shares or other equity securities by our company will constitute an additional source of liquidity and capital resources. We could use the proceeds of any future equity offering in the development of our businesses. In addition, to the extent that, consistent with our longer-term strategy, we pursue acquisitions of transmission businesses or assets in North America, we may issue equity securities to fund, or to constitute the consideration paid by us for, any such acquisitions.

Risk Management and Quantitative Disclosure Concerning Market Risk

We have an enterprise risk management program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic business objectives.

While our philosophy is that risk management is the responsibility of all employees, the Audit and Finance Committee of our board of directors has been mandated to review annually our company's risk tolerances, its risk profile and the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. Our Investment Review Committee has recently been designated as the executive oversight committee for business risks. Our Chief Financial Officer is responsible for the ongoing monitoring and review of our risk profile and practices and will work in close association with the Investment Review Committee to ensure that the risk management program is an integral part of our business strategy, planning and objectives. Each of our subsidiaries is required to complete a formal risk assessment program and to develop a risk mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer, the Investment Review Committee and the Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing holding company and subsidiary risk tolerances, preparing risk assessments and profiles and assisting line and functional managers in fulfilling their responsibilities. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in interest rates, currency exchange rates and commodity prices, chiefly for purchases of power and gas.

All of our long-term debt outstanding at December 31, 2001 is denominated in Canadian dollars and bears interest at various rates, with a weighted-average interest rate of 8.0%. We are exposed to fluctuations in interest rates as maturing debt is refinanced and periodically utilize interest rate swap agreements to mitigate elements of the interest rate risk. At the end of 2001, offsetting interest rate swap agreements with the same counterparties were outstanding with notional principal amounts of $167 million. These agreements mature in 2011. We estimate that a 1% change in interest rates on the refinancing of long-term debt maturing in 2002 and 2003 would affect net income by $1.2 million in 2002 and $4.2 million in 2003. Accordingly, we estimate that a 1% increase in weighted-average interest rates in respect of our indebtedness will not have a material effect

on our results of operations for 2002 or 2003. We cannot make any prediction concerning actual interest rate movements in 2002 or 2003.

Although we are not currently exposed to fluctuations in currency exchange rates, we may decide in the foreseeable future to issue foreign currency debt or to enter into business arrangements concerning foreign operations.

We do not believe that our regulated transmission and distribution businesses will be exposed to commodity risk after Open Access, as the Ontario Energy Board allows all distributors to pass commodity costs through to their customers. We will continue to experience volume risk with the opening of the market. Rates for our transmission and distribution businesses are based on projected electricity consumption levels. A significant reduction in actual consumption levels from projections could negatively affect the rates of return of these businesses. In the event of reductions resulting from unusual circumstances, we could apply to the Ontario Energy Board for a rate redress.

Our activities in the competitive retail market, conducted through our unregulated subsidiary, Ontario Hydro Energy Inc., are exposed to price and volume risks, both of which we intend to manage. These risks arise from different prices, volumes and other conditions in supply contracts as compared to prices negotiated with customers and their actual volume requirements. We intend to limit our exposure to commodity price and volume risk in the competitive retail market through contract-matching techniques and the use of electricity and gas derivative financial instruments. We have entered into electricity swaps with Ontario Power Generation Inc., which are effective upon Open Access for a term of five years. Under these transactions, we will pay fixed prices ranging from $45 to $50 per MWh on a total notional volume of 906 GWh and receive a variable price. In addition, total retail electricity sales of approximately 8,500 GWh with sale prices averaging approximately $59 per MWh remain unhedged. We are pursuing opportunities to enter into full requirements electricity and gas supply contracts with established energy marketing and trading companies. Under such arrangements, the trading company would fulfil actual customer requirements, thereby assuming substantially all of our commodity price and volume risk associated with the provision of energy.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. Currently, we have no significant concentrations of credit risk with respect to any class of financial assets. Our revenue is earned from a broad base of customers and we currently do not earn a significant amount of revenue from any single customer. However, with the introduction of Open Access, we will be required to procure wholesale power on behalf of competitive retailers and distribution companies connected to our distribution network for resale to their customers. We intend to mitigate the resulting concentrations of credit risk through the use of various security arrangements, including letters of credit, which will be incorporated into our service agreements with these retailers and companies in accordance with the Ontario Energy Board's Retail Settlement Code.

Derivative financial instruments result in exposure to credit risk because of a risk of counterparty default. Other than our interest rate swaps, all of our derivative financial instruments have been entered into by Ontario Hydro Energy Inc. We monitor and attempt to minimize credit risk through various techniques, including dealing with highly-rated counterparties, limiting total exposure levels with individual counterparties and by entering into master agreements which enable net settlements of obligations between parties.

Environmental Risk

We manage a number of environmental risks that are primarily related to contaminated land, PCBs, spills and leaks. We have developed specific environmental management programs for these risks, including a program to systematically assess and remediate, if necessary, contaminated land and a program to identify and safely destroy or dispose of PCB-contaminated equipment. We also have a program to respond to spills and to reduce the amount of insulating oil leaking from equipment.

We estimate our future expenditures associated with land assessment and remediation and PCB management. As at December 31, 2001, our current estimate for future expenditures associated with land assessment and remediation is approximately $83 million. For the purpose of this estimate, we assume that remediation will be conducted, as necessary, where contamination exists off-site or poses an on-site risk to human health. We have also assumed that the Ontario Ministry of the

Environment, the Federal Department of Indian Affairs and Northern Development and affected Indian bands will support our approach to assessment and remediation and that existing environmental regulations will not change. As at December 31, 2001, our current estimate of future expenditures for PCB management is approximately $163 million. This estimate assumes that existing environmental regulations regarding PCB management will not change. Our estimates are reviewed regularly and we currently expect to incur these PCB-related expenditures through to the end of 2020. As at December 31, 2001, our estimated present discounted value for future expenditures under both programs was approximately $174 million. A regulatory asset in this amount has been established that reflects our expectation of recovery of these expenditures through our future rates.

Risks Related to Transfer of Assets on Indian Lands

We are exposed to financial risk associated with the cost to complete the transfer to our company of title to transmission, distribution and other assets located on Indian lands in connection with the acquisitions of our operations as of April 1, 1999. Transfer of title to these assets did not occur because authorizations originally granted by the Minister of Indian Affairs and Northern Development (Canada) for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant Indian bands or bodies or, in several cases, because the authorizations had either expired or had never been properly issued. We manage these assets, which are currently owned by Ontario Electricity Financial Corporation.

We have begun negotiating with the relevant Indian bands and bodies to obtain the consents necessary to complete the transfer of these transmission, distribution and other assets. We cannot predict the total amount that we may have to pay to obtain the required consents. We expect to pay more than the $850,000 per year that we are currently paying to these Indian bands and bodies and that is the total amount of allowed costs in the transitional rate orders. If, after taking all reasonable steps, we cannot otherwise obtain the consents from the Indian bands and bodies, Ontario Electricity Financial Corporation will continue to hold these assets for an indefinite period of time. Alternatively, we may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial or, in a limited number of cases, abandon a line and replace it with diesel generation facilities. In such cases, we would apply to the Ontario Energy Board to recover these payments or costs in future rate orders.

Risk of Recovery of Market Ready Costs

In March 2002, the Ontario Energy Board approved our application to recover approximately $8 million of the costs we incurred to align our systems and practices with those of the competitive electricity market in Ontario, commonly referred to as Market Ready costs. Total Market Ready costs for our transmission and distribution businesses are estimated to be $110 million. The process and timing for the approval of the remaining amount spent has not been established, although we expect any recovery of these costs to be over a period of years. We have informed the Ontario Energy Board of this estimate and have deferred the costs for accounting purposes, adhering to the initial criteria established by the Ontario Energy Board. The Ontario Energy Board has the discretion to examine and assess the extent to which these Market Ready costs may be recovered.

Related Party Transactions

Prior to the Offering, the Province owned all of our outstanding common and preferred shares. Upon closing of the Offering, the Province will retain some special voting rights in limited circumstances and may retain an ownership interest. In addition, the Province owns all of our preferred shares, which we are obligated to redeem within 120 days of the closing of the Offering.

As of April 1, 1999, we acquired substantially all of the assets, liabilities, rights and obligations of the electricity transmission, distribution and energy services businesses of Ontario Hydro pursuant to transfer orders under the *Electricity Act, 1998*. Ontario Electricity Financial Corporation has agreed to indemnify us with respect to the failure of the transfer orders to transfer any asset, right or thing or any interest therein related to our business to us and some of our subsidiaries, some adverse claims or interests of third parties or based on title deficiencies arising from the transfer orders, except for some claims and rights of the Crown, and claims related to any equity account previously referred to in the financial statements of Ontario Hydro including amounts relating to any judgment, settlement or payment in connection with litigation initiated by some utilities commissions. The Province has agreed to unconditionally and irrevocably guarantee to us and our subsidiaries the payment of

all amounts owing by Ontario Electricity Financial Corporation under its indemnity. Ontario Electricity Financial Corporation held approximately $3 billion of our debt as at December 31, 2001. Ontario Electricity Financial Corporation has advised us that it intends to resell in the Canadian debt capital markets by March 31, 2003 the approximately $2.5 billion of our debt held by it which matures after 2002. In addition, we have engaged in, and will continue to engage in, transactions with affiliates of the Province, including Ontario Power Generation Inc. The Province also has general policy directive powers over the Ontario Energy Board, which is our principal regulator.

In addition to the foregoing, we have engaged in extensive transactions, and have significant relationships, with the Province and its affiliates and agencies and bodies during the entire period covered by our financial statements and to date. See Note 18 to the Consolidated Financial Statements for the three-year period ended December 31, 2001.

Critical Accounting Policies

The preparation of our financial statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting policies involve the more significant estimates and judgements used in the preparation of our financial statements:

Regulatory assets and liabilities. We operate in a regulated environment. As a result, regulatory assets and liabilities arise as part of the rate-making process. These assets and liabilities can be recognized only to the extent that the Ontario Energy Board accepts the relevant regulatory treatment. If the Ontario Energy Board subsequently determines that a regulatory treatment is no longer acceptable, that regulatory asset or liability would no longer be supportable and, accordingly, would be charged or credited to the statement of operations in the period in which that determination is made. The following items give rise to regulatory assets: employee future benefits other than pension; Market Ready costs incurred to align our systems and practices with the requirements of the future competitive electricity market in Ontario; and estimated future expenditures required to remediate past environmental contamination. Pension costs give rise to regulatory liabilities.

Environmental liabilities. We estimate our total liability for remediation of past environmental contamination and management of PCBs based on the net present value of these estimated future expenditures. We also review estimates of future environmental expenditures on an ongoing basis. These future expenditures are estimated in accordance with current environmental laws and regulations and current estimates of long-term interest rates. If environmental laws and regulations or long-term interest rates change, the net present value of our environmental liabilities will be affected.

Employee future benefits. We provide employee future benefits to our current and retired employees, including pension, group life insurance, health care, workers' compensation and long-term disability.

In accordance with our transitional rate orders, we record pension costs when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Based on the last actuarial valuation of pension fund assets and liabilities as of December 31, 2000, we have had a contribution holiday and, as such, are not required to make contributions to the pension fund until, at the earliest, the next actuarial valuation, which will occur no later than December 31, 2003.

We record employee future benefits other than pension costs on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. These assumptions include a weighted-average discount rate, the rate of compensation scale escalation, the rate of cost of living increase, the rate of increase in long-term medical costs, as well as the rate of increase in dental costs. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of current and retired employees covered.

Employee future benefits included in labour costs and charged to operations or are capitalized as part of the cost of fixed assets. Changes in the assumptions will affect the amount of the employee future benefits and the current year charge to the statement of operations or amount capitalized to the cost of fixed assets.

In general, in the event that our estimates and judgments incorporated in the above critical accounting policies differ from actual results, or if the Ontario Energy Board, for any reason, does not allow or accept our accounting treatment reflected in these policies or changes its position in respect of any of these policies, then the resulting effect on our results of operations and financial position could be material.

Reconciliation to U.S. GAAP

Net income was higher under Canadian GAAP by $4 million in 2001, and $68 million in 2000 than would be the case under U.S. GAAP. Of the $68 million difference in 2000, $60 million was the result of the timing of recognition of costs associated with staff reduction programs. Retained earnings were lower under Canadian GAAP by $25 million as at December 31, 2001, and by $29 million as at December 31, 2000 than would be the case under U.S. GAAP. See Note 25 to the Consolidated Financial Statements for the three-year period ended December 31, 2001 for a description of the principal differences between Canadian GAAP and U.S. GAAP, as they pertain to us.

The U.S. Financial Accounting Standards Board, which is commonly referred to as "FASB", issued a series of new accounting pronouncements in 2001. See Note 25 to the Consolidated Financial Statements for the three-year period ended December 31, 2001. Other than as described below, we do not anticipate that these FASB accounting pronouncements will have a material effect on our results of operations or financial position. The effect of Statement of Financial Accounting Standard No. 143, *Accounting for Asset Retirement Obligations*, which relates to the accounting treatment of obligations associated with the retirement of long-lived assets, is not yet determinable, but could be material in terms of our results of operations and financial condition under U.S. GAAP.